Appraisal of Oil and Gas Properties

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THE original manuscript for this book included several tables of value to the appraiser that it has not seemed feasible to include in this volume. A list of these can be obtained from the University Book Store, University of Pittsburgh, Pittsburgh who can supply a set of mimeograph copies.

PREFACE

ONLY in the last few years has the valuation of oil and gas properties been so developed as to reduce errors to a reasonable magnitude. It is not surprising that serious valuation was not attempted until the passage of the income tax law forced the task upon the producers. Properties must be sold, purchased, taxed, or for gas they must be made the basis of rate increase. To facilitate this, the work in hand has been prepared.

The authors have added as many of the tables which are of fundamental importance in appraising a property as space would permit. In addition, there have been incorporated some new tables and charts which will be of value in reducing the work of appraisal to such limits that it may be undertaken with less frequent resort to mere guessing.

The chapters have been arranged in the order generally carried out in making an appraisal. Where the discussion is applicable to both oil and gas there is a caption to that effect. Other discussions relative to oil or gas only are marked as such. In diagrams, especially, where the applicability is interchangeable, the more difficult example is illustrated. The material in the last four chapters and the appendix has a general bearing on appraisal, although not a part of the order of procedure mentioned above.

The authors wish to acknowledge the suggestions and assistance of L. G. Huntley and that given by members of the staff of Johnson, Huntley & Somers. Through their efforts and interest it has been possible to incorporate much original data.

To Marjorie Park Ruedemann and Mary Simonds Johnson the writers are indebted for aid in the preparation of the manuscript for the printers.

—The Authors.

Titles of Chapters

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Chapter I

KINDS AND PURPOSES OF APPRAISAL

Oil or Gas

Purposes.—The engineer about to attempt the appraisal of oil or gas properties must first determine the purpose for which the work is intended. The amount of detail and degree of exactness depend upon this point. It may be that (a), a valuation of certain assets, or of expected return is desired, to ascertain whether the outstanding stocks is listed at a low or a high figure, or (b), a property may be offered for sale, and a comparison of actual value to price asked be required, or on the other hand, (c), there may be an opportunity for disposal of a property and the advisability of so doing is the question, or (d), the owner suspects that the income is not commensurate with the exchange value so that sale would be the more profitable course, or (e), the time has come when cost of operation approaches gross income and an application to the public utilities commission must be filed and a valuation determined to adjust rates, or lastly (f), an appraisal is essential to the proper computation of allowable depletion deduction, or the estimating of invested capital for federal taxation.

For some of these, one method of valuation suffices, but for others a different angle of approach is required. In some the amount to be determined is the only goal. In others a more or less elaborate demonstration of the findings requires the presentation of extensive data.

In gas, a great contrast exists between the tax appraisal and the rate making appraisal, since in these cases extraneous elements enter which prevent the closest possible approximation of a true appraisal. In the one case there are various limits as to allowable range which the department uses in its judgments, and the study of both its formal findings and its action on appraisals is essential to the preparation of an acceptable appraisal. In rate cases, either court or commission, the decision known or thought to be approved by that particular tribunal must be followed, or at least considered. In the valuation of oil properties, otherwise than for taxation, there are no such restrictions to hamper in the choice of methods which are most scientific with the data available.

The necessity of conforming to such restrictions especially in relation to future price will, in most instances, result in a valuation which fails to coincide with that made for commercial use.

The actual investigation on costs by bodies such as the Federal Trade Commission have revealed such wide variation as to greatly surprise economists as well as the public. They clearly see of what little practical use is the determination of average costs and hence of average valuation figures for specific application.

Types of Appraisal Now in Use.—The most common, and probably the most arbitrary type of appraisal is the inventory method. All physical property is inventoried and the value established. Production is valued on the basis of producing acreage at a uniform rate, and the undeveloped acreage at an arbitrary lesser uniform amount per acre. After completion of the computations, an addition is made for intangible values usually a percentage of the tangibles. Some flexibility is possible by the introduction of stepped values. Much depends upon the skill and experience of the appraiser in respect to the values, but the method is not capable of utilizing to full advantage that knowledge and experience.

Other appraisers in valuing acreage allow a certain amount per unit of well capacity. This tends to establish values somewhat commensurate with the relative size of the wells, but by ignoring entirely the rate of return of the production leads to gross errors in the absolute values. Physical equipment is generally, of course, a relatively simple problem and offers few variations in method. It is the valuation of oil or gas reserves that offers the greatest difficulty.

Another method used is to make an estimate of recoverable reserves without regard to rate of extraction. These estimates are generally based on the history of amounts recovered per acre foot from pools already exhausted. Such an indiscriminate application of results from one locality may produce an error of several hundred per cent. Amount of recoverable reserves per acre foot often varies many fold in very short distances. Each unit of reserves estimated, usually one barrel, or one thousand cubic feet, is then multiplied by the net revenue expected. The determination of the rate of return and of the present worth are omitted from the computations. This type of appraisal, although preferable to a simple inventory, has too high an error to warrant decisions involving investment or sale. There are those who are willing to trust it for tax and rate-making purposes, but with a wider knowledge of method to be later described, its use will be gradually restricted to those small companies and operators where the general efficiency is low.

An old, and up to the present time the most commonly used method for calculating values is the "barrel-day" rule. This "rule of thumb" originated in the Pennsylvania fields and was originally stated thus:

"The value of settled production per barrel is one thousand times the posted price of crude."

With this rule as a basis, the bartering parties raise or lower the unit value, dependent upon their opinion as to the "settled" condition of the wells, the age of the wells, the condition of the equipments. The phrase "settled production" is only a relative term and should not be used until the yield of one year exceeds eighty per cent of the previous year.

Annual analytical appraisal methods provide the best means of applying the desirable degree of refinement. In this case, the recoverable reserves are estimated in such a manner as to permit calculation of the yield expected each year. Consequently, annual net income can be postulated and a compound discount factor applied to obtain present worth. It offers opportunity for varying the degree of refinement to that with the exactness demanded for the purpose of the appraisal.

Development of Annual Analytical Appraisal Methods:—The fact that oil and gas are migratory and cannot be recovered at a rate which can be planned beforehand, as with metal and coal mining, has been the principal cause of delay in the application of scientific methods. The final and necessary impetus was provided by the government's demand for valuations in connection with income tax and the lack of sufficient and acceptable transaction data to establish value by comparison.

The annual analytical method, as stated before, has been a gradual development and was first applied to oil property appraisals and later to natural gas. The first steps were in the estimation of future reserves for wells. Prior to the publication of Lewis and Beal's Bulletin[1], the Oil and Gas Manual[2] and Beale's Bulletin No. 177[3], little had been printed concerning decline in production.

Requa[4] was probably the first to seriously study the rate of decline of oil wells as being of prime importance for valuation. This was followed by Washburne's volumetric saturation method[5] for determining oil content and later in the year Arnold's[6] paper giving a theory on the decrease of production.

Several text books discuss the methods of estimating future yields of which those by A. Beeby Thompson[7], Bacon and Hamor[8], Johnson and Huntley[9],

1.—Lewis, J. O. and Beal, C. H., Some New Methods for Estimating the Future Production of Oil Wells; Bulletin 134, February, 1918.

2.—Treasury Department, Bureau of Internal Revenue, Manual for the Oil and Gas Industry, Government Printing Office, 1919, Revised edition, 1921.

3.—Beal, Carl H., The Decline and Ultimate Production of Oil Wells, with Notes on the Valuation of Oil Properties Bureau of Mines, Bull. 177, 1919.

4.—Requa, M. L., Present Conditions in California Oil Fields, Bulletin No. 64, April, 1912.

5.—Washburne, C. W., The Estimation of Oil Reserves, Bulletin 98, February, 1915.

6.—Arnold, Ralph, The Petroleum Resources of the United States, Economic Geology, December, 1915.

7.—Thompson, A. Beeby, Petroleum Mining and Oil Field Development, 1918.

8.—Bacon R. F. and Hamor, W. A., The American Petroleum Industry, 1916.

9.—Johnson, R. H. and Huntley, L. G. and Somers, R. E., Business of Oil Production.

Johnson, Huntley & Somers[10], and McLaughlin[11], are the most important.

A resume of the methods presented up to 1917 was given by Pack[12].

Following the development of methods for getting output, various principles for valuing oil lands were presented. Lombardi's[13] paper was one of the earliest, followed a year later by Hager[14].

Although Requa[15] had very much to do with the development of the early appraisal methods it was not till 1918 that his valuable work in this field became public.

His paper outlines the state of the art just before interest was centered in appraisal through government requirements in 1919, and the valuable work of the Bureau of Mines written by Lewis and Beal.

The application of annual analytical appraisal methods to natural gas properties lagged behind that for oil, due to greater difficulties in estimating future reserves. However, the reliability, even in this more difficult field has now been so increased as to make it of great aid in an industry of outstanding hazard and uncertainties.

Advantages of Annual Analytical Appraisal Methods.—There is no doubt that an annual analytical appraisal best represents a property's worth. The method is still belittled by men unfamiliar with its details, or incompetent to understand it, and, in some cases, such disparagement is justified through the failure of the appraiser to properly apply the principles thereof, or to use them with inadequate data. When inefficiently carried out, such an appraisal is likely to be more disadvantageous than beneficial. It requires a combination of adequate data and sound method to result in the desired reliability.

The chief advantage lies in the reduction of the number of loose, broad estimates and the increase of closer measurements of the separate component elements. The various predictions are each based, so far as possible, on a collection of facts derived from the history of previous performance, or in the case of prices and operating costs, on history and the prevailing economic conditions surrounding the commodity.

The greater exactness and thoroughness with which results are obtained are the commending features. The examiner has in hand a compilation of data open to analysis and criticism to the smallest details. Clashes of opinion are minimized, as the principles upon which the method is founded eliminate haphazard estimations. A record is left behind indicating past operations and future prospective operations.

While all other types of appraisal must at bottom rest on future earnings, only in this method is this problem clearly recognized and directly attacked. The final results in the annual analytical method are determined by the income anticipated from the operations of the property in the future. A method that directs itself to the real value has a great superiority in that it permits, after completion, comparison with the selling price. A knowledge of the amount of this difference is of great value to the executive.

In addition to the determination of future earnings, a history of past operations is compiled. A careful study of this compilation may suggest a reorgan-

Factors Entering into an Annual Analytical Appraisal.

1. Present Tangible Property

- A. Field
  1. Wells (Drilling Machinery, Operating Equipment.)
  2. Lines
  3. Shop
  4. Warehouses
  5. Leaseholds
- B. Transmission Line (gas)
  1. Mains
  2. Pumping Stations
  3. Condensers
- C. Distribution System (gas)
  1. Low Pressure Mains
  2. High Pressure Lines
  3. Reducing Station
  4. Regulators
  5. Service Connections
  6. Meters
- D. Headquarters
  1. General Offices
  2. Branch Offices
  3. Telephone Lines
  4. Real Estate

2. Present Intangible Property

- A. Going Value
  1. Interest during construction.
- B. Good Will
  2. Losses during construction and expenses. (Competitive Enterprises only)
- C. Going Concern Value
  1. Necessary Promotion Costs
  2. Value of Organization in making of addition and replacements.
- D. Vested Rights
  1. Franchise (gas)
  2. Rights of way
  3. Leaseholds (Only under certain conditions.)

Items applying to Natural Gas industry only marked gas.

3. Operating Costs

- A. Maintenance
  1. Materials
  2. Labor
  3. Supplies (a. field
     b. transmission (Gas)
     c. distribution (Gas)
     d. office)
- B. Taxes
  1. Local
  2. State
  3. Federal
- C. Insurance
  1. Accidents
  2. Elements
  3. Fidelity
- D. Executive
- E. Well Royalties
  1. Flat Annual Rate
  2. Quantity Basis
- F. Conducting business
  1. Labor
  2. Superintendence
  3. Office
- G. Rentals
  1. Real Estate
  2. Undeveloped Leases
- H. Bad Accounts
- I. Advertising
- J. Traveling
- K. Interest
  1. Running Accounts
  2. Stocks of Supplies

4. Sale Price

- A. Direct Revenue
  1. Domestic Use (Gas)
  2. Industrial Use (Gas)
  3. Sale of Crude
- B. Sale of by-products
  1. Gasoline
  2. Lamp Black (Gas)
  3. Helium (Gas)
- C. Other Income
  1. Steam sales
  2. Water sales
  3. Fuel for drilling

5. Future Production

- A. Revenue Production
  1. Oil or gas produced (Producing Wells, Undeveloped Area.)
  2. Gas Purchased (Present Vendors Prospective Vendors.)
- B. Non-Revenue Production
  1. Blowing Gas Wells
  2. Transmission Loss-Gas (Gathering Lines.) Suction Lines, Transmission Mains, (Leakage and Condensation), Distributing System.)
  3. Free Gas (Royalty Owners. For Franchises.)
  4. Gas Used (Compressors, Auxiliary Machinery.)
  5. Fuel used in drilling

6. Future Construction and Development

- A. New Plants
- B. Maintenance of Supply
  1. Wells
- C. Warehouses
  2. Lines
- D. Telephone Lines
  3. Powers

11.—McLaughlin, R. P., Oil Land Valuation.

12.—Pack, R. W., The Estimation of Petroleum Reserves, Am. Inst. of Mining Engineers, August, 1917, pg. 1121-1134.

13.—Lombardi, M. E., The Valuation of Oil Lands and Properties. International Engineering Congress, San Francisco, Cal., Sept., 1915. Later published with additions in Western Eng., Vol. 6 October, 1915, pg. 153-159.

14.—Hager, Dorsey, Valuation of Oil Properties. Eng. and Min. Jour., Vol. 101 pp. 930-932, May 27, 1916.

15.—Requa, M. L., Method of Valuing Oil Lands. Am. Inst. Min. Eng., Bulletin 134, February, 1918, 409-428.

ization of the system, with increased efficiency. It may also bring out the fact that under particular market conditions it is better to dispose of certain assets than to continue to operate them. In fact, a company which has had no analytical appraisal will find the knowledge derived from it sufficient to warrant the expense even though the valuation is unnecessary for taxation, exchange, or rate making.

Outline of Annual Analytical Appraisal Methods.—The fundamental steps in the making of an annual analytical appraisal are:

1. Estimation of future yields.
2. Prediction of future prices.
3. Prediction of future costs of operating.
4. Prediction of future costs of development and improvement.
5. Determination of discount factor to be used.
6. Estimation of investment risk.
7. Estimation of line and underground loss (for gas only).
8. Valuation of physical property.
9. Consideration of factors indirectly affecting the calculations.
10. Valuation of intangibles (in some instances).

Of these, the first four are of major importance.

Given the estimated future yield on producing wells, the net income per annum can be computed by considering the future price of the oil or gas and cost of operating in conjunction therewith. In addition, the prospective profit on undeveloped locations is necessary, with due allowance for the cost of development to be incurred. Each well, or group of wells, and locations, because of risk require a reduction to compensate for this hazard. The future net income is then discounted to prevent value by a factor dependent upon certain conditions. This final result can be divided into value of physical property and value of oil or gas reserves. The valuation of intangibles may be in addition to, or part of the gross amount found for the above items, and depends upon the nature and the method of valuation used. Where all the future gross revenue can be ascertained, the intangible value is indirectly involved in the gross earnings.

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Chapter II
DEFINITIONS
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MANY new words and phrases have been introduced into valuation work within the last few years. A number of expressions are used to define more than one thing. This was inevitable since several investigators were simultaneously developing methods to use in appraisal. The authors are, therefore, explaining the meaning applied to words and phrases used in this work. They have attempted to avoid the coining of new expressions, except for very good reasons, and to adopt such as are widely used when they are not misleading.

Annual Analytic Appraisal

"Analytic appraisal" is the determination of value by segregation and study of all the components involved in present and future earnings. "Annual analytic appraisal" is a consideration of these components in yearly time periods. The primary factors entering into such an appraisal are, estimated future production, future price, future operating expenses, future cost of replacements and extensions, equivalent present value and salvage value.

"Value" is the relative desirability of possessions or services as measured in barter and exchange by some standard of purchasing power. It is largely regulated by the relative power and desires of the bargaining parties. "Value" should not be confused with original cost. Value may be more, or less, than such cost. Engineers recognize that the value of a utility, such as a natural gas plant in operation or a group of properties, is not the sale value of the physical units but a value established by the earning capacity. Supply and demand of natural gas go far toward the determination of value, but are not the sole determiners. Value thus defined has little relation to the utility of the service the public receives. In the case of oil prices the influencing factors are much more complex because less local.

"Fair Market Value"

This term came into common usage through federal taxation requirements. The version applied for that purpose is retained in this volume. It is defined as the price that would be paid in a transfer between a willing seller and a willing buyer, as of the particular date. Considerable latitude is necessarily permitted in ascertaining what would be fair market value where there is an absence of transactions of similar properties at that time. The adjective fair is properly added only when there is freedom from all elements of coercion. There may be fair market value even though a property may not be on the market or where no agreement can be reached in the barter. Where a property is disposed of through compulsion, the spirit of fairness no longer exists. Further, market conditions may be so abnormal that although a sale has been consummated to the apparent satisfaction of all concerned, no fair market value has been established.

"Physical Value"

Physical value is the value of material things such as machinery, rigs, etc. Physical property is that which can be precisely inventoried.

"Non-physical or Depletable Value"

This comprises those values which arise from the fact that an operated oil or gas property, like a mine, is a wasting asset; for every unit of these natural resources that may be removed causes a reduction in the remaining real worth. Only rarely can the extent of such natural resources be determined closely in advance. Depletable value, that is, that value which is affected by the exploitation of the property, may even be estimated as to the undeveloped but semi-proven acreage, but in such cases a considerable error must be expected. Obviously, the more nearly proven it becomes, the more weight may be ascribed to its value, but until the products are actually in the tanks or in the pipe lines, the hazards inherent in the industry require recognition of these uncertainties.

When in the ground, the hazards incident to calculation of the amount and bringing it to the surface make it akin to the property classed as "intangible values." Although some operators refer to recoverable reserves as intangible value this is not common and is becoming less so. When oil is in the tanks, or gas is in the lines, and in position to be marketed, it approaches closely in its characteristic the things classed as having "physical value," but it is not so included.

"Intangible Value"

The third and last group of values comprising the whole for an oil company or a natural gas utility is intangible value. This applies to all elements of value other than the physical and depletable values. Found in this group are, franchise value, leasehold value, rights-of-way, rights-of-ingress and egress, going value, going concern value, good will, and others of like nature.

(a) **"Going Value."**—This is distinctive from "going concern value" and should not be confused with it. "Going value" covers the cost to the owners of bringing the enterprise to a self-supporting basis. This value will include early, necessary, losses and the cost of developing the business.

(b) **"Going Concern Value."**—This is a broader term than going value. This is the value possessed by the going organization in excess of the mere physical and depletable value of its units in its then state of efficiency and operation. This may in the case of some organizations be very large in comparison. In others it may be zero or even negative.

(c) **"Good Will."**—This is an intangible value existing ordinarily only where there is close competition by a like business venture. The existence of only one gas company in a community makes it in the nature of a monopoly and as such it cannot be said to have any good will, except where the attitude of the public is such that if competition were introduced, it would choose to buy from the company which had enjoyed the monopoly. A business trust gains trade out of necessity, and not always through desire of the individuals to patronize it. Yet the reputation of its product or the possession of a trade name such as "vaseline" may be good even where competition is unimportant. "Good will" may constitute a large part of the "going concern value" of an organization.

(d) **"Franchise."**—A franchise is a privilege granted by a community to a corporation permitting it to engage in a business in that particular locality. The authority may be that of a municipality, state or nation and may be by legislative action or from an administrative individual or board. The value of a franchise depends upon the stipulations of the instrument, and the productivity of the privilege.

(e) **"Rights-of-way."**—This is the license granted a company to lay pipe lines across certain properties. The value of rights-of-way enhances with the number of rights obtained for a contemplated project.

(f) **"Leasehold."**—This is a right to enter upon the property to explore for and remove from its underground reservoir any existing oil or gas for a consideration payable in proportion to yield or at stated intervals.

The value of the leasehold right as a possible oil or gas resource should not be confused with the intangible value of leaseholds. The value of the oil or

gas rights is covered under depletable value. The intangible value of leaseholds develops only where by proper blocking, more efficient operation and a saving of investment is to be realized.

"Investment Risk"

This term covers all hazards to which the owners of a company are exposed. There are in general three groups of risk:

(a) **"General Risk."**—General risk covers all hazards other than dry hole and well abandonment. Both administrative and economic risks are included. The economic hazards are those affecting the costs of operations, materials and the sale prices. The administrative risk is that of retaining such ability and integrity as the management possesses.

(b) **"Dry Hole Risk."**—This term covers the hazard of field exploration work. Wells being drilled, and not yet drilled, are subject to this risk.

(c) **"Risk of Abandonment."**—This expression has been adopted in this volume to indicate the hazards encountered in recovering the gas from its reservoir. Estimations of future reserves can only be approximated by theoretical computations. If, in making this estimate of future reserves, the history of all wells that produced is used, a risk factor for possible abandonment is not required except as conditions change. This risk is automatically provided for in large part when predictions are based on a complete history of the regional wells.

"Graph Paper"

This is paper with crossed lines called the grid. It is used to picture graphically tabular data and also to facilitate predictions and extrapolations. There are many kinds of graph paper of which the following are most commonly used:

(a) **"Rectangular Co-ordinate or Quadrille."**—On this paper the x and y scales are both arithmetic and generally found in divisions of an inch or centimeter. In this work the paper is usually referred to as co-ordinate paper.

(b) **"Semi-logarithmic."**—Paper on which the one axis is to an arithmetic and the other to a logarithmic scale. Usually the x axis is the arithmetic one. Exponential curves are straight lines when plotted on this graph paper. It also aids in more conveniently illustrating curves of very rapid increase.

(c) **"Logarithmic."**—Both scales are logarithmic. A hyperbola becomes a straight line when plotted on this graph paper. It is much used in production decline curve extrapolation as these curves are usually hyperboloid.

"Scatter Diagram."—Altho the points plotted do not fall, in a straight line they are plotted on the graph paper and a curve drawn through the averages of consecutive columns or the area of greatest density. Rarely maximum and minimum curves are also drawn.

"Closed Pressure."—Throughout this volume the term "closed pressure" is used in preference to "rock pressure." It means the pressure as registered in pounds per square inch at the well head. If taken as the pressure above atmospheric pressure it is called gauge pressure, or if the pressure of the air is added it is then distinguished as absolute pressure. The measure of closed pressure is determined at the mouth of the well by gauge readings made when a condition of stability is assumed to have been attained in the reservoir. The reservoir is merely the interstitial space of the producing sand and is limited in extent by water, the texture of the sand and cementing material occupying the space between the particles of sand. As the gas and oil are removed the closed pressure is reduced under some one of the following conditions which apply to different reservoirs:

(a) Reservoir of fixed volume.

(b) Amount of oil and gas increases by inflow of additional oil and gas from the adjacent low porosity rocks as pressure is reduced.

(c) Volume of reservoir contracts as oil or gas is exhausted by inflow of water. Rate of depletion in this case is therefore more rapid than it appears by the rate of pressure decline.

"Initial Production."—This term when used herein will indicate the production of the first twenty-four hours (or the average daily production for the first several days, in which case the term will be qualified.)

"Economic Limit."—The economic limit is the stage at which no profit can be realized from the recovery and sale of the oil or gas. For gas the abandonment pressure and economic limit might be synonymous, and should be, if proper records of operating expenses are kept. The theoretical economic limit for appraisal is not necessarily the economic limit chosen by the company. Their policy is generally to extract the product until the income from sale does not warrant maintenance, usually with gas until the income is less than the rental paid to the lessor. This throws the burden of recovery, transportation and marketing of the amount recovered from these wells upon the larger and more profitable producers.

"Settled Production."—As used in this publication in connection with oil, is the stage when the yield of a year is 80 per cent or more of the previous year. This ratio is called the persistence of the well at that time. It is frequently applied earlier in the life of the well, but such usage is misleading.

"Composite Decline Curve"

A curve made up from the history of several producing wells or leases is designated as a "composite decline curve." There are numerous methods for using the well data to make a composite decline curve. The majority of these were originated for oil wells, but have been found to apply to gas wells also. Various degrees of accuracy, speed and feasibility characterize these methods. The names and principles used in the construction of the principal types of curves, applicable to oil and gas, are as follows:

(a) **"Time Decline Period Method."**—This term is applied throughout this volume for a method sometimes referred to as the "segmental method." The phrase "time decline period method" is more expressive of the principle used in the construction of the curve. In making the tabulation preliminary to the curve, the time required for each well to decline from one designated size to another designated size is listed in the column covering that particular stage of decline. By summation and averaging, the data for an average curve are secured. This method can be used with any kind of producing records. It is rapid and free from the personal equation, as well as easy for assistants to comprehend.

(b) **"Percentage Decline Method."**—In the "Percentage Decline Method" to construct the curve find the percentage which the production of each year bears to that of the first year. This operation is carried out separately for each well. These percentages are listed according to age in the proper columns of a table, and an average is calculated. The averages are the points for a composite curve. The neglect of the important size element makes this method of little value.

(c) **"Shingling Method."**—The "family curve" devised by Beal is more descriptively called the "Shingling Method" because of the appearance of the many curves as grouped for the drawing of the composite curve. The method is similar in principle to the "Time Period Method" and gives nearly the same results. Instead of finding the points for the composite curve by tabulation and averaging, a graph is made of the several individual wells or leases on one chart, the largest well being plotted first and the others in succession according to size, the starting point of each being a point on a master curve representing the control tendency of the decline in production up to this point from the curves already drawn. It has the advantage that instead of the precise mean a "central tendency" may be chosen by the eye, which will frequently be sounder than the actual mean. For a few wells this method is feasible and rapid. Where there are many wells, these must be grouped and the resultant curves so constructed later used in the same way to make a final curve, thus making the method slower.

(c) **"Age-Size Method."**—In the "age-size method" both age and size are the influencing factors for the construction of the composite curve and the reading of future reserves. It is, therefore, free from the error in the law of equal expectation which disregards age. The preliminary step is to plat in a scatter diagram the first year's production against that of the second year, and on another diagram the second year against the third, and so on, making a total of one less diagram than the number of years life of the largest wells. More frequently the five-six diagram is made a year-succeeding-year diagram and used for the remaining life. Next, the points on each diagram are con-

nected in succession by a line. With this line as a guide, a smoothed line is drawn between the points. If the points are numerous an average line is calculated by averaging columns. From these preliminary diagrams the composite decline of a series of wells may be found by taking any initial yearly production as the starting point, and in the first diagram finding the second year's production, from the second diagram the third year's production, and thus continuing the process to the economic limit. Composite, or general curves, can be drawn for a series of hypothetical well readings. Although longer, the time spent in construction is amply repaid by the refinement obtained. The greater the number of wells the greater the degree of accuracy attained. The method is less applicable where only a few records are available.

"Persistence."—This is production of oil or gas by any well, or aggregate of wells, for any unit of time, divided by the production for a previous time unit, and expressed as percentage. Persistence may be used in reference to pressure instead of production, if stated as "pressure persistence." The unit is understood to be a year, unless otherwise indicated by prefixing the adjective quarterly, monthly, weekly or daily. 100 per cent is complete persistence and means there has been no decline.

"Slope Angle."—This is the angle that the straightened production line on logarithmic paper makes with the axis of the abscissa. It is assumed yearly units are used unless stated to the contrary.

"Future Estimated Production."—The "future estimated production" may be stated in total amount, or divided into the amounts anticipated for each year. The phrase is sometimes shortened to "F. E. P." by using the initial letter of each word.

"Ultimate Reserves." — The total amount of production from a well or pool, from time of beginning to abandonment, is the ultimate recovery or reserves. It is "recovery" if the oil or gas has already been produced and "reserves" if the production is predicted or anticipated. The ultimate production of a producing field or well is production to date plus the amount estimated as likely to be recovered.

"Cumulative Percentage Curve."—A curve first published by Lewis and Beal in which the production of the first year is given as 100 and the cumulative percentage on this basis is given for each succeeding year.

"Ultimate Cumulative Percentage."—This is the cumulative percentage as above at abandonment or expected abandonment of the well.

"Segmentation."—The word "segmentation," when referred to in curve construction, means the division of the composite decline curve into segments yearly or by size and arrangement of the segments into columnar order. This arrangement greatly facilitates the reading of future production.

"Operating Costs."—Although the term generally applies to the cost of operating the whole plant; for the appraisal methods described in this book, it indicates the cost to produce the oil or gas, that is, to bring it to the surface and in a position to be transferred to the pipe line or to be transported to the consumer. Repairs, labor, field supplies, superintendence in the field, and other miscellaneous expenses, along with a share of the general office expense are all involved in the well operating cost. In a few instances the broader definition of the term is used, namely to cover the operating costs for the whole plant.

"Compound Discount Factor."—When finding out how much a certain amount of money will be increased by compound interest at a given rate in a certain number of years an interest table is referred to and the increased amount found. On the other hand, a sum of money which is to be obtained during certain future years has, at the present day, less value by reason of the fact that it is not now available. A prudent investor would not pay one hundred dollars for an equivalent amount to be received ten years hence. The amount he would probably pay is one that will amount to one hundred dollars when increased by compound interest for ten years. The factors used in finding the present day value of amounts to be realized at some future day are termed "compound discount factors."

There are primarily three kinds of compound discount factors, each depending upon the method of investing the capital returned or the redemption fund. Each set of factors is calculated differently to agree with the policy of the controlling organization or individual in the manipulation of returned capital. They are:

(a) Where the redemption fund is not increased by interest.

(b) Where the redemption fund is increased by interest at the same rate as that being returned on the investment.

(c) Where the redemption fund is increased at a different rate from that being returned on the investment.

"Redemption Fund."—The term "redemption fund" indicates an amount set aside as partial recovery of the investment. The redemption fund is theoretically increased from the earnings each year, so that by the time the investment, if in physical equipment, is ready for replacement the original cost has been recovered. This may be done by a complete return of cost or a partial return, which, when increased by interest for the term of years remaining to the end of the life of the property, becomes equivalent to the original cost. The terms "sinking fund" and "redemption fund" are synonymous.

"Deferred Receipts."—Deferred receipts are the future gross earnings postulated in the appraisal.

"Deferred Development."—This is a prediction of some future expenditure in equipment, drilling or other extension.

"Deferment."—This term is used to describe time that elapses before some future expenditure or earnings materializes.

"Present Value."—The expression "present worth" is synonymous with "present value" as used in analytic appraisal.

"Depreciation."—The decreased worth of an article through wear and tear, obsolescence, inadequacy, or otherwise, is depreciation. The causes of depreciation more fully defined are:

(a) **"Normal Wear."**—This is the decline in usefulness and value due to the constant process of abrasion, crystallization from repeated blows and other deteriorating agencies that are proportionate to use. Careful maintenance may delay the time of complete decrepitude but will not prevent it. This depreciation arises from usage.

(b) **"Obsolescence."**—The introduction of some new kind of machinery or article which would sufficiently increase the efficiency and warrant the removal of the old machinery or article, is depreciation by obsolescence.

(c) **"Inadequacy."**—The increased demand of service, or the change of amount of service and supply may cause an article to become uneconomical and thus so inadequate as to be replaced or discarded. Sometimes civic improvements necessitate a change in gas lines which constitutes another form of inadequacy.

(d) **"Physical Deterioration."**—This arises from the effect of decay, corrosion or similar deteriorating agencies which are not proportionate to use but which are proportionate to age. The process goes on whether or not the property is used and is distinctive from "wear and tear" in this respect.

(e) **"Accidents and Negligence."**—The effects of fire, and of high wind, water and extreme cold, on physical property comes under this head of accidents. Whether avoidable or unavoidable they often hasten the depreciation of an article. Negligence may cause accidents, but can also be a cause for increase in the rate of decay by lack of interest on the part of the individual responsible for the condition of the equipment.

(f) **"Deferred Maintenance."**—Necessary repairs may be delayed through indifference, neglect or lack of finances. Normal repairs maintain the life af an article; "deferred maintenance" hastens the depreciation.

(g) **"Other Factors."**—Parasites, insects and animals preying upon the wood or metal increase the rate of depreciation. Electrolysis, through short circuiting of the overhead trolley, causes a disintegration of the structure of pipes and consequent shortened life. Underground waters frequently corrode wall casing.

"Appreciation."—This is the increase in value of physical property, real estate or depletable property through economic conditions.

"Realized Appreciation."—For federal taxation, deductions from gross income for depletion and depreciation on the basis of the value as of certain dates are permitted. The difference between the deduction allowed as based on value, and what it would have been if based on actual investment is realized appreciation. The regulations specify under what conditions realized appreciation may be added to invested capital as part of the surplus and undivided profits.

"Depletion."—The diminishing of the supply of oil or gas in the underground reservoir is depletion. Depletion may be in terms of barrels, M cubic feet, or dollars and cents. If the latter, it is a pro-rata return of capital invested, or value, as the case may be. The proportion is found by calculating the amount removed during the year to the reserves on the date of investment or valuation.

"Capital Account and Invested Capital."—These terms are synonymous and mean the cost returnable, either through depletion or depreciation. The cost must have been capitalized to be included as part of the capital account or investment.

"Capital Sum."—This is a special phrase used by the Income Tax Unit to describe that total value which is subject to allowances for depreciation or depletion according to the regulations. Capital sum is the amount of the value returnable through either procedure; if it be depletion, it is depletable capital sum; if depreciation, it is depreciable capital sum.

"Unit Cost."—This is the cost or value as of a certain date divided by the future reserves as of that date. It is usually in dollars and cents per barrel or M cubic feet. The unit cost multiplied by the production for the year gives the monetary depletion allowance. "Unit cost" is used also as descriptive of a method of depreciation or physical property valuation. Such usage is not common, however, and is not likely to be conflicting.

"Averages."—Two kinds of averages are used in this volume; one the simple arithmetic mean and the other the weighted arithmetic mean. The simple average need hardly be described. The weighted average, however, is more complex. Suppose the corporation sold X quantity of oil at R cents per barrel and Y quantity at S cents per barrel. the weighted average price per barrel received for the year would be:

$$\frac{R\,X + S\,Y}{X + Y} \text{ and not } \frac{R + S}{2} \text{ as found}$$

by simple average.

Oil

"Relative Value Curve."—A curve devised for use in fixing valuations by comparison with transactions. The curve is one showing relation of future reserves to barrel day price.

"Price Adjustment Curve."—A curve used in compensating for the lack of uniform return of future production and the future price of oil as predicted on the basis of uniform annual increments of increase or rate of increase.

"Casinghead gas."—Casinghead gas is that gas which occurs at oil wells. This designation arises from the fact that at pumping wells the gas is chiefly derived from the space between the tubing and the well casing, and passes therefrom through an opening in the casinghead. However, flowing oil wells are frequently accompanied by large volumes of gas and this also is called casinghead gas. Casinghead gas is sometimes called 'wet' gas and is thereby differentiated from the so-called 'dry' gas, which is obtained from wells that yield gas only and no oil, although there may be enough gasoline vapor for extortion by absorption plants. Dry gas wells are the principal source of the large-volume supplies of fuel gas for industrial and domestic distributing systems.

Gas

"Fair Value."—This term is most commonly used in placing valuations on public utilities. The 'fair market value' and 'fair value' should be synonymous but the latter expression has a meaning not so clearly definable and more indefinitely used. For the purpose of purchase or sale, assuming prudent parties on both sides, the value would be based on the plant as an income making organization; assets and prospective earnings being the guiding factors. For rate-fixing, the courts specify fair value shall be the basis for the rate, but fail to agree as to what elements comprise fair value. As a result, divergent views have developed, and 'fair value' can therefore only be defined as the value upon which the courts allow a calculated return to the owner.

"Fair Rate."—The 'fair rate' is the amount of return based on 'fair value' allowed an owner. There must be a knowledge of operating and all other expenses, as well as the local conditions, risk of the business and other factors, which, with the fair value, combine to determine the 'fair rate' of return. This term is found in Public Utility valuations for rate making purposes.

"Line Pressure."—'Line pressure' is that pressure in pounds per square inch exerted by the gas at the point of measurement in a pipe line. Line pressure may be naturally produced by well pressure, or artificially produced by pumps. Gas entering one end of a long pipe line at a given pressure will be found to decrease in pressure with distance from point of entrance unless influenced by other wells or artificial compression.

"Minute Pressure."—Minute pressure readings are taken by permitting a well to flow freely against atmospheric pressure for a short while, then closing a gate valve and observing the rise. [illegible] ssure. The pounds pressure gained in the first minute above atmospheric taken immediately before closing the gate, gives the minute pressure. If the well is not "blown" as a preliminary but the gain in pressure starts at line pressure, it is minute pressure above line. The increase in pressure in one minute is a theoretical means of ascertaining the flow of gas from the well. The errors in obtaining the reading and in the assumption on which the method is based are so great that the readings of many wells must be combined and correction factors applied to approximate the capacity of the group.

"Open Flow Capacity."—This means as the term implies, the capacity as found by tests, when a well is flowing freely into the air. The term open flow is synonymous with natural flow. Pitot tubes with manometer or spring-gauges are used to register the velocity of flow. Of the several methods for obtaining capacity of wells, this is passing out of use because it is so wasteful.

The capacity by minute pressure above line tests is based on the flow into a known container, (the hole from the sand to the gauge,) whereas, in open flow tests, it is measured by the velocity in escaping through an opening of known diameter.

Well capacities, when designated by open flow tests, are far greater than well yields for the following reasons:

(a) Under operating conditions gas wells flow against a line pressure which is usually greater than atmospheric pressure.

(b) Wells are not operated regularly for 24 hours daily, as often assumed by promoters when giving an account of a well's size. Repairs, accidents and the necessity to shut in wells to replenish a depleted supply by migration, reduce the actual time in use.

(c) When there is a relatively high line pressure then the delivery into the line is only a small fraction of the amount registered by the open flow reading.

"Time in Line."—The expression of time in line refers to the days per week, months or years that a well was permitted to flow into the transmission lines. The importance of time in line is evident when the reserve estimate of wells and their rate of recovery is made. Some wells are held in reserve and operated in times of peak load only; others are operated almost continuously. When off season load permits, wells are closed in and allowed to "build up." This is desirable because the migration through the pores in the producing horizon of the well may be slower than the rate of flow from the wells. The well can thus be put into condition to yield more during a short pull at peak load.

"Line Loss."—In being transported from the well to the consumer more or less gas leaks from the line. Line loss will not be correctly measured by metering at the two ends where differ-

ent pressures prevail. If calculating tables are used which are based on the assumption that natural gas is a perfect gas, (that is follows Boyle's law that volume times pressure equals a constant), an error is introduced, as natural gas is more compressible at high than at low pressures.

"Abandonment Pressure."—In some fields, because of water and other conditions, the flow of gas is stopped at a relatively high pressure. The pressure at which no further production can be expected, or is so small that no profit accrues, is known as abandonment pressure.

"Closed Pressure-Production Curve Method."—As the name implies, the method utilizes both closed pressure and production. The closed pressure decline serves as a measure of the rate of decline, and the production is used to obtain the relation between pounds pressure and the amount of production for the decline in pressure of an average well. The closed pressure decline curve is constructed first using any of the methods previously described. By calculation, a scale of production is determined and the future reserves read as desired, either in pounds pressure or M cubic feet.

This method with the data usually obtainable is one of the most reliable as minute pressure production estimates are made irregular by the variation in the line pressure, and the open flow tests are not of sufficient frequency to be feasible.

"Closed Pressure-Minute Pressure Method."—This is another method for estimating future reserves differing from the Closed Pressure-Production Curve Method in that an effective minute pressure curve, is drawn in relation to the magnitude of closed pressure. The minute pressure curve is on a scatter diagram, with closed pressure as the ordinate and minute pressure as the abscissa.

"Field Reduction Factor."—Where estimates of production in the field are made by other than meter tests, a correction factor must be applied to the gas sold, to obtain the gas produced. The correction factor necessary is herein termed "Field Reduction Factor." It is obtained by correcting the gas sold to consumers for line loss, free gas distributed and gas purchased.

"Field Price."—In certain appraisals the price of gas at the well, not that to consumers, is necessary. This well price is called field price. It may be ascertained by direct sales or purchases in the field, or by distribution of consumer's price to the various units or systems.

"Production System"—Wells, leases, and equipment necessary to produce gas are all grouped together and termed the production system. All operations incidental to the recovery of gas belong to this group.

"Transportation System."—The plant necessary to carry gas from the well to the distribution lines is called the transportation system. It consists mainly of pipe lines and compressing stations.

"Distribution System."—The lines, meters, offices, etc., essential to the carrying of the gas from the transportation lines to the consumer, as well as the administrative machinery to collect bills and maintain the equipment, are all classed under distribution system. For each system such labor, superintendence, repairs and other current expenses as are connected with the system are designated as belonging to it. The general overhead is proportionally distributed to each system by various schemes.

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CHAPTER III

Organization of Work

Oil or Gas

SURVEY OF WORKING DATA.—Previous to attempting any work, a complete survey should be made by the engineer in charge. A portion of each feature of the detailed work and computations should be carried out so that there may be no delay or difficulty in giving intelligent advice to assistants.

Because of the various kinds of production tests it is more difficult to plan for natural gas than for oil appraisal. The purpose of the appraisal and the number of properties will determine the amount of time it is advisable to spend upon preliminary analysis of the records. A week is not too long for one man to spend in studying the available information of a company that has 2000 wells. During the progress of the work an outline of the data with remarks as to the source thereof can be made.

Probably the most difficult preliminary study is that of the company organization in connection with valuation for federal taxation. In the report, the manner of or organizing, the acquisition of assets, dates of completion of wells and many other features all covered in the regulations promulgated by the Internal Revenue Bureau, and pertinent to the company, require specification. No other work can be carried out until a complete outline of the facts bearing on the questions of the law involved is made. The entire appraisal hinges on whether or not certain things are permissible under the exacting conditions. In appraisal for commercial purposes these questions of legality do not ordinarily enter.

Preliminary Appraisal

It is advisable to carry out a complete appraisal of a group of small wells. In the process, contingencies likely to arise in the valuation of the other wells should be listed for later use. If the type of curve and other methods chosen for the test appraisal give sound results then the organization of the work can begin.

Organization of Data, Work and Summary Sheets

(Depends upon the magnitude of the job. Samples of all work data and summary sheets can be devised.) The size of sheet acceptable to the company official can be adopted. As a rule, books of odd shape or unusual size cannot be conveniently filed. However, there should not be too much sacrifice to standardize the size of sheets to a particular filing nook.

The work sheets are those being used for assembling of information and making preliminary computations. Mimeograph or multigraph copies of adopted forms are suitable. The more complete the headings and rulings for these sheets the greater the efficiency. Although work sheets will not be bound into the reports presented to the officials, it is advisable to keep them organized and in good condition, for a need may arise to refer to them at some later date.

The data and summary sheets are those to be bound into books and presented with the report. The detail involved depends entirely upon the use to which the appraisal is to be put. Some appraisal reports need be only a short summary of results, while others must contain sufficient detail to permit checking by engineers not familiar with the company, its records or anything in connection therewith.

Oil company data and summary sheets are not so complicated as those for gas companies. The data for a property can generally be placed on one long sheet. There are also fewer work sheets and production difficulties. Failure of the pipe line to take the full production is the most serious handicap to the preparation of suitable decline curves, but is fortunately not common.

Time to Start the Appraisal Proper

All work data and summary sheets should be printed and ready for use by the time an appraisal is undertaken. Efficient plans for labor distribution are difficult to maintain since the duties change as the work progresses. The personnel should include one or more non-technical assistants for the purpose of copying or calculating as this comprises too large a part of the work to be done wholly by engineers economically. On a large appraisal accountants are indispensable to obtain data from ledgers etc., in which case a draughtsman will also be an economy.

Filing System

It is desirable to adopt a system of filing records when the task is prolonged. The larger the number of properties the more important and detailed the filing system becomes.

CHAPTER IV

Calculation of Past and Present Yield Oil

Purpose. Prior to any estimation of future yield by decline curve methods, it is necessary to calculate what amount has been recovered and the rate of this recovery.

Methods of Estimating Production. There are two main sources of information. One consists of the past record as shown in the record of periodic gauges taken by the lease boss of the company, the pipe line run tickets and the record of sales of the oil. This last should be taken into account in connection with the division order to the pipe line which shows amount of royalty and, if any, possible "top-royalty." The custom of the district or of the pipe line as to correction for water, b. s., allowance for pumping, correction for temperature unless already know, should be ascertained. Sometimes where the data are fragmentary they can be supplemented by the gross production tax return to the state where the state is one levying such a tax.

The other source is a specifically gauged run under check conditions for the satisfaction of the prospective purchaser who has a representative on the ground. This run is especially desirable as it gives an opportunity to learn how the production and any accompanying water is distributed among the wells. Besides the obvious precautions it is desirable to detect whether the wells have been "rested" prior to this gauge in order to increase it. The best check on this is to compare each day's yield. Where a gauge is taken it should be by individual tanks at least. Some attention should be given to getting the behavior of the individual runs by such means as may be feasible.

It is a mistake to place too much value on a 10, 15 or 30 day gauge as against the past record as the latter has the advantage of including the vicissitudes of the season cycle and of hazards.

The greatest difficulty arises in finding the amount of production attributable to new wells when the production therefrom is run into the same tank as the other wells. It is not reliable to use the flow estimated by swabbing or other methods for appraisal purposes. The principle is to draw a decline curve on the production of the old wells, and by projection, calculate the share of the daily or monthly flow attributable to the new well.

Gas

Purpose. In general, natural gas companies act as their own marketers,

transporting their product to the place of distribution. Only in rare cases is gas measured in the field. Even when purchased from small producers it is often tested only periodically and payment made on the basis of open flow, pounds close pressure or pressure above line. Thus the gas appraisal engineer must develop methods of determining the gas produced in the field, a task not required of the petroleum engineer. These computations are probably the most difficult phase of the whole work.

The best measure of production is, of course, by meter. Estimates are made from open flow capacity tests or minute pressure tests after the blowing or above line. Closed pressure (often called rock pressure) tests are used as a means of estimating the proportion of gas exhausted in comparison with initial pressure. Only when used in connection with production do they indicate the volume in cubic feet.

Segregation of Production Into Units to be Valued. Tests made to estimate production are inaccurate for various reasons and require correction. In the valuation of a company's production on the basis of profits to be realized from producing, transporting, and distributing the gas, estimated production must be corrected for line loss or for the error in reading or that in testing. Since profit is only realized on the gas actually sold, all corrections of test estimated production will have to be pro-rated over the amounts of gas distributed to the various towns and cities where it is sold. Because of line loss, a correction percentage, to allow for the amount of gas salable at the point of consumption, will be greater than one where the production is for valuation in the field and line loss is not a factor. The procedure in obtaining these correction percentages is outlined in Chapter V.

Production by Meter Tests in the Field. Where meters are installed in the field, no further tests are necessary to get production estimates. Meter readings are the standard by which production is determined and therefore the best obtainable information. Any company with meters in the field should avail itself of the opportunity to test the validity of the various methods of estimating gas flow. These experiments would prove very valuable in the choice of a testing system for the particular conditions when meter testing is undesirable.

Production by Minute Pressure Above Line Tests. A common practice among companies is to estimate the capacity of gas wells by quickly shutting the gate or valve leading to the line and noting the pressure on the gauge each minute. The amount of the first minute reading above the line pressure taken before closing the gate is designated as effective minute pressure.

The volume of the part of the hole through which the production is drawn times the effective minute pressure gives the approximate flow.

The minute pressure test for one well has little significance in the calculation of future reserves or production. The readings for a number of wells are essential to a true average. The sum of all the estimates for the group, when corrected, gives the approximate production of the company. A small group of wells is little better than a single well.

For several reasons, minute pressure readings seldom indicate the rate of decline of production. A common practice is to turn small wells into the line

Chart For Computing Capacity Of Gas Wells

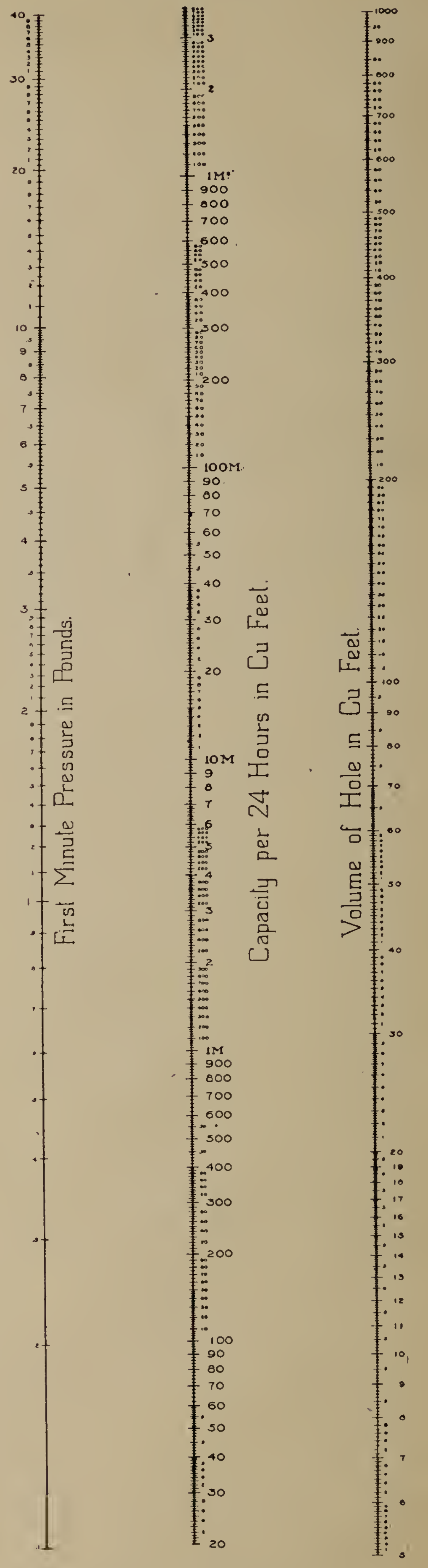

Fig. 2.—Chart for calculating daily production when given the volume of the hole and the first minute pressure above line or atmospheric pressure

(Courtesy R. E. Davis)

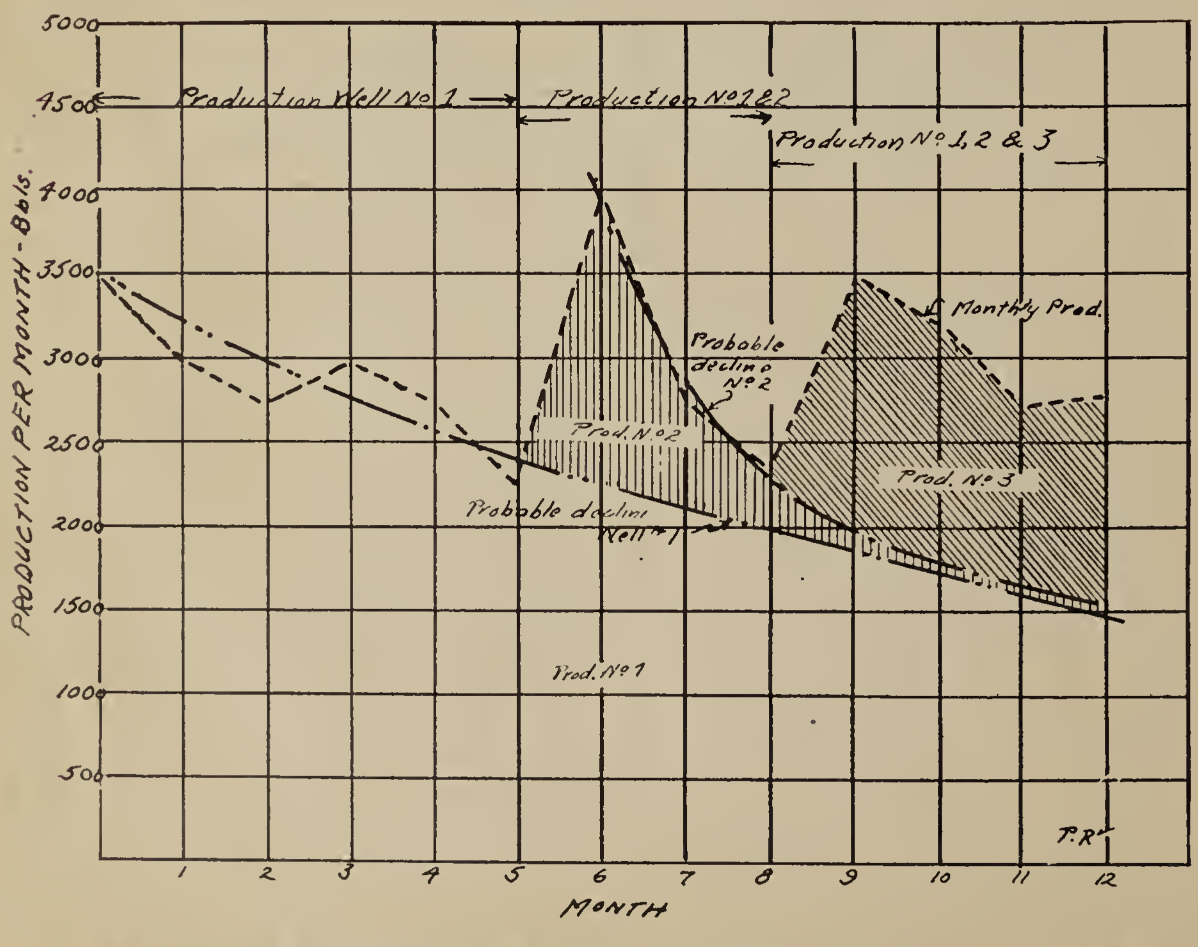

Fig. 1.—Graphic method for estimating production of new well which is run into same tank with that of other wells

when the line pressure is low. Correspondingly, the large wells are shut in at periods when a low line pressure is desirable. Examination of many wells for several companies revealed a condition of similar effective minute pressure each year for a number of years. The wells had been turned into the line for a short time each year, always under suitable line conditions. When new, the closed pressure being high, the wells were turned into the line at the time of a high line pressure The gradation of line pressure from high in winter to low in summer, and the turning in of the wells at times when the closed pressure was just above the line pressure, resulted in the condition of uniform minute pressure above line readings. Thus all possibility of determining the decline in the rate of production for the wells was eliminated.

Computation of Minute Pressure above Line Production by Graph. Rather than do all the multiplications and divisions necessary to obtain a result, it is often both practical and economical to resort to graphs. Since well production estimates start with an original indeterminable error due to reading, the final computations can safely be carried out on a chart. For this purpose a diagram using Westcott's[1] factors has been arranged. Logarithmic paper has been used for convenience in interpolating, as the lines are parallel on this paper. On quadrille paper the lines would radiate from a common point zero.

A chart is very easily made. Three scales are required; the left, as the length of the pipe; the lower as the volume of the pipe; and the right scale as flow per day or other unit of time. The computations for volume of a hole for hundred foot lengths of various pipe diameters is given in the Handbook referred to above.[2] Having laid out the length and volume scales, plot points for the volume per hundred foot length for each diameter given; then for the volume of the thousand foot length for the same diameters, the latter being ten times the former. Connect points for similar diameters, thereby establishing the first set of lines. Given the volume of the hole, multiplication with the factor gives the flow per minute or day, as desired. Suppose it is to be in daily amounts. The Handbook gives the flow per day per unit of volume for each minute of effective pressure to the probable limit of the well size. Assume wells of 10, 100, and 1000 cubic feet volume respectively. Plot the factors, multiplied by 10 for the 10 foot volume, by 100 for the 100 foot volume, and by 1000 for the 1000 foot volume. Draw lines through the points representing similar pressures, and the chart is complete. For convenience in reading, a system of line coloring can be adopted.

Another type of chart for the same calculations has been devised on the nomographic or alignment principle.[3] This type chart is very practicable and rapid but has the disadvantage of being difficult to construct and awkward to carry or file, as folding is apt to destroy the relation between the lines. Reproduction can only be carried out by methods not liable to change this relation, and therefore blue printing and photography are impossible.

Another type of alignment chart which has been used to advantage in appraisal work omits the lines for calculation of the volume of the hole.[4] Figure 2 is a reproduction of a large copy of such a chart. To find the capacity of the well, connect with a straight edge the points for the volume of the hole and the effective minute pressure as found on the two outer lines. The point of crossing on the center line indicates the production per day in M. cubic feet. (It was necessary to reduce this greatly, but the relationship has been preserved — Editor.)

Production by Open Flow Tests of Gas Wells. Open flow tests are generally regarded as a fairly accurate and convenient way of determining the flow of gas. To facilitate this, an instrument called the Pitot Tube with a pressure gauge is used. The Pitot Tube measures the velocity of flowing gas. It consists of a small tube, with one end bent at right angles, which is inserted in the flowing gas. At a convenient distance from the end (from one to ten feet) an inverted siphon or U-shaped gauge, which is filled to the zero mark with water or mercury, is attached. Wells of large pressure are measured by a pressure gauge instead of a Pitot Tube.

For convenience, a scale graduated from the center in inches and tenths of inches is attached between the two limbs of the U gauge. The distance above and below this center line at which the liquid stands at the gauge should be added, the object being to determine the exact distance, in inches and fractions thereof, between the high and low side of the fluid.

The well should be blown off until there is little change in its rate of flow, In practice this is highly variable, varying from ½ hour to 24 hours. Three hours is common practice. For further details and precautions, and for tables giving the flow corresponding to the velocity pressure of the gas flowing from the well, consult Westcott's "Handbook of Natural Gas."

As in the case of minute pressure capacity estimates, those ascertained by the open flow method must be corrected to the amount a meter would give if placed at the well.

Calculation of Open Flow Capacity By Graph. A very excellent chart for the calculation of open flow capacity from the readings has been recently developed.[5] It provides for type of reading, size of pipe and specific gravity of the gas. Pipe sizes, other than those shown, can be interpolated with reasonable accuracy. If flow is desired for other periods of time than twenty-four hours, the scale at the top can be computed with this in view.

Correction for temperature can be made by adding or deducting 1 per cent for each 10° F. above or below 60° F. flowing temperature. For corrections, when the specific gravity of the liquid in the testing tube is other than one, the scale at the extreme left with different specific gravities has been added. The same provision is made for variations in the specific gravity of the gas. The directions for the solution of problems are found accompanying the chart.

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[1] Westcott, Henry P., "Handbook of Natural Gas." Metric Metal Works.

[2] Page 259.

[3] Foraker, F. A., Directions for Using Chart to Compare the Capacity of Gas Wells: Natural Gas, Volume 11, No. 9, Sept. 1921, pp. 26, 27.

[4] Published by courtesy of R. E. Davis, consulting engineer, Pittsburgh, Pa.

[5] Milliken, C. V., Pitot Tube Chart: Natural Gas, Vol 11, No. 8, Sept. 1921, p. 21.

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Chapter V

LINE AND UNDERGROUND LOSS AND FIELD REDUCTION FACTOR OIL OR GAS

UNDERGROUND Loss.—The loss of oil or gas into the earth from the well after it leaves its reservoir is often very heavy and sometimes is never detected. This oil or gas may later be yielded from a higher sand into which it has flown, but often is wholly lost. The appraisal engineer ordinarily provides for efficient operating in the estimates. Still it may be that the wells taken as a basis for the valuations are the only ones suffering a loss and therefore the others are incorrectly valued.

The principal losses discussed by Ambrose[1] are given as follows:—

(1)—In recovery methods.
(2)—Through improper or unsystematic casing.
(3)—To a well out of control.
(4)—By improper drilling methods.
(5)—To perforating all sources.
(6)—By not knowing producing zone.

(1) Losses in Recovery Methods.—This subject has been especially well covered by Lewis, who gives the estimate that from 80 to 90 per cent of the oil underground is not extracted[2]. He also takes up methods of increasing the recovery.

It is important to the appraiser that efforts are being extended to this end, as otherwise estimates of production predicted by him may not be substantiated. The study involves the compressed air process, the use of regulated back pressures, of gas or vacuum pumps, and of water displacement; also questions of shooting, swabbing, the rate of pumping and cleaning out of wells and the use of acids and electrical or steam heating to increase production.

(2) Loss through Improper and Unsystematic Casing.—This accounts for much underground loss. Improper casing permits water to migrate to the oil or gas sand and frequently taps part of the contents. Another loss is through the escape of the oil or gas to higher formations. There has been much written about the various means of remedying water trouble.

(3) Loss Due to a Well out of Control.—When wells are shut in because of the lack of storage facilities or pipe lines trouble may develop, especially with large wells. If the casing is not well seated the oil or gas, under the great pressure, may break through to other formations and gradually enlarge the hole causing collapse.

(4) Losses by Improper Drilling Methods.—The loss here is mainly by migration of oil or gas to upper sands when the casing has not been properly set, while drilling is going on.

(5) Loss Due to an Upper Sand.—Loss by this means is commonest in gas fields where an operator often attempts to recover the product from more than one sand at a time. Since one of these is generally under higher closed pressure than the other, migration of "vagrant gas" is sure to occur. The upper sand may not be competent to hold a pressure higher than its natural one, or it may be tapped by wells of competitors.

(6) Losses caused by Not Knowing Producing Zone.—Large losses may be caused by the failure of the operator to realize the exact location of the producing zone. In wildcat wells, the producing sand may not be known, and with rotary drilling it may be overlooked. With cable tool wells oil may be overlooked when there is water in the hole and the sands are not tested with a bailer.

Oil

In addition to the general losses mentioned above there are certain losses particularly connected with the competition of extracting a vagrant mineral. Should the property to be valued be at a disadvantage as compared to its competitors in the following respects deduction must somehow be accomplished depending on the conditions, as compared with a property which is in all respects on a parity with its neighbors.

1. The neighboring property has wells along the boundary (even though at the standard distance for the region, from it) which are producing while the property being appraised is still only being drilled or possibly the wells have not even started. The loss of pressure still more than the loss of oil at these wells cuts down seriously the amount to be produced from the property. This of course, is variable and is greatest where—

(a) wells are largest
(b) the sand is very porous
(c) under high pressure
and (d) the pool is small in area.

Some operators have delayed drilling thinking to wait for a better price. It is too dangerous a procedure in nearly all cases where the neighbor will not co-operate.

2. If the neighbor keeps a lower pressure at his casing head by withdrawing the casing head gas faster he pushes the "tension" line from which oil flows to one or the other property, and possibly toward the appraised property with a loss to it.

3. If the neighbor places his offsets closer than usual to the boundary line, thus forcing overdrilling around the borders he will reduce the percentage of oil extracted from the central part of the lease or else drill additional ones not otherwise needed. The value of the property is thus reduced.

4. If the neighbor places his own offset wells too close together, the appraised lease operator must suffer a loss of some of his oil or a loss by extra drilling in similarly spacing his own wells.

The existence of a co-operative agreement to avoid these practices is thus a real value. whereas an avowed purpose or obvious prosecution of them is a negative element. This whether it alters revenue or expenditure.

In planning the rapidity with which wells will be brought in, which the appraiser must do, he should be guided by the express or apparent intention of the management which will own the property. If that cannot be obtained or is for any reason improbable, he must construct the program that seems most likely to be carried out, not necessarily the wisest possible program; to make the losses as low as possible, the profits greatest.

Gas

Calculation of Line Loss.—The estimate of line loss can only be made between two or more points at which the gas is measured. Compression stations on the main lines generally measure the amount passing. The consumer's meters give the final estimate. Free gas distributed, gas purchased and gas sold between the two points should be allowed for.

Factors Affecting Line Loss.—It has been found that very few companies show any similarity in line loss for equivalent distances. The reasons are: —

1. Difference in the kind of pipe joints.
2. Efficiency in line maintenance.
3. Topography of the region.
4. Size and age of the lines.
5. The pressure in the line.

An approximate total loss of 20 per cent for each thousand miles of line, which includes gathering, transportation and distribution, has been taken as a reasonable assumption where no infor-

1—Ambrose, A. W., Underground Conditions in Oil Fields: Bull. 195, Bureau of Mines, 1921. pp. 160-166.
2—Lewis, J. O., Methods of Increasing the Recovery of Oil from Sand: Bureau of Mines, Bull. 148, 1917, p. 26.

mation on line loss is available. This is liberal and is derived from the average of several companies operating under varying conditions. Since the range of loss for the distance was found to be from 7 to 57 per cent, specific calculation should always be made where possible.

The percentage of loss finally adopted in the appraisal should be an average for a number of years if possible. Any recent radical change in conditions would limit the period of time for historical compilations.

Underground Loss.—This loss is often material, but as a rule unknown. All calculations of production are at the mouth of the well and therefore no correction is necessary for gas lost between the producing sand and the surface. However, this unrecoverable loss means reduced revenue, and, like line loss, can be eliminated to a large degree by efficient operating. If definitely known, it would limit the use of analogous wells in making a future decline curve.

Field Reduction Factor.—The field reduction factor is the amount by which production calculated in the field differs from that estimated to be the field production from more accurate measurements. The line loss computation is for the purpose of taking measured production at some point along the line and correcting it to the field amount.

Chapter VI

ESTIMATION OF FUTURE YIELD PRODUCING WELLS; METHODS AND DECLINE CURVES

Oil or Gas

With the numerous principles and methods advanced in the last few years for the estimation of future reserves, it becomes necessary to make a choice when preparing an appraisal. Naturally the primary considerations should be accuracy and adaptability to the records available. Next in importance is the speed with which the estimates can be made. No single step affects the final results as much as the method and accuracy of calculating the reserves. If refinement is omitted in this part, then refinement throughout the remainder of the work becomes useless.

The Junior author recalls the checking of many appraisals submitted to the Internal Revenue Bureau in which the reserve estimates were so crudely made that an error of from at least 30 to 50 per cent was certain, and yet the discount factor was carried to six decimal places.

Construction of Decline Curves.—There are many methods proposed for the drawing of composite or average decline curves. The Bureau of Mines has been making a study of the advantages of each method. Nearly all methods are based on the law of equal expectations, which as expressed by the authors thereof, is as follows[1]:—

"If two wells, under similar conditions, produce equal amounts during any given year, the amounts they produce thereafter, on the average, will be approximately equal regardless of their relative ages."

The following methods to be described. are based on this law:—

1. Time decline period.
2. Percentage decline.
3. Cumulative percentage.
4. Shingling or family curve.

Although reasonably reliable results are obtained by each method, when carefully applied, they omit the important variable of the age of the well. The age-size method[2] considers this element, and for commercial appraisal will give more accurate results than the methods which omit this factor.

In the demonstration of all except the cumulative percentage curves, actual production figures taken from one pool, have been used.

(1) **Time Decline Period Curve Method (Segmental)**[3].—This method is variously referred to as the Darnell or Segmental method. The name herein chosen is descriptive of the process required in construction. The method is one of those based on the law of equal expectations by Lewis and Beal.

The curve is made from arithmetical averages of the time it takes each well to decline from one given size to another. The choice of the size depends entirely upon the accuracy desired. The production data for each well were plotted on co-ordinate paper and a smooth curve drawn through the points. This facilitates the reading of decline periods and leads to more accurate results.

The following table illustrates the arrangement of data:

Tabulation Showing Time to Decline from One Given Size to Another Given Size

Gross Barrels Per Year

	9000 8000		8000 7000		7000 6000		6000 5000		5000 4000		4000 3000		3000 2000		2000 1000		1000 500		500 250		250 50		50 Ec.Lt.	
Well	yr.	mo.	yr.	mo.	yr.	mo.	yr.	mo.	yr.	mo.	yr.	mo.	yr.	mo.	yr.	mo.	yr.	mo.	yr.	mo.	yr.	mo.	yr.	mo.
1		2		2		2½		2½		2½		8		11	2	6	1	4	1					
2				2		2		2½		3		3		5½		10	1	7						
3				3½		4		3½		5		5½	1	1½	1	10	2	3						
4								2½		3		2½		3		9	1	10						
5							1	1	1	4	1	9	2	8	7	7								
6										3		4		4		8½	3	4						
7														10	1	6	2	0						
8																	1	8	1	4				
9																			1	4				
10																	1	1	2	2½				
11																			1	10				
12																			3	2	11			
13																			2	10				
14																			1	5				
15																			2	5	3			
Total		2		7½		8½	2	0	2	8½	3	8	6	7	15	8½	15	2	16	8½	14		4	
Average	0	2	0	2½	0	3	0	6	0	5	0	7	0	10½	2	3	1	10	2	1	7		4	
Cumulative	0	2	0	4½	0	7½	1	1½	1	6½	2	1½	3	0	5	3	7	1	9	2	16	2	20	2

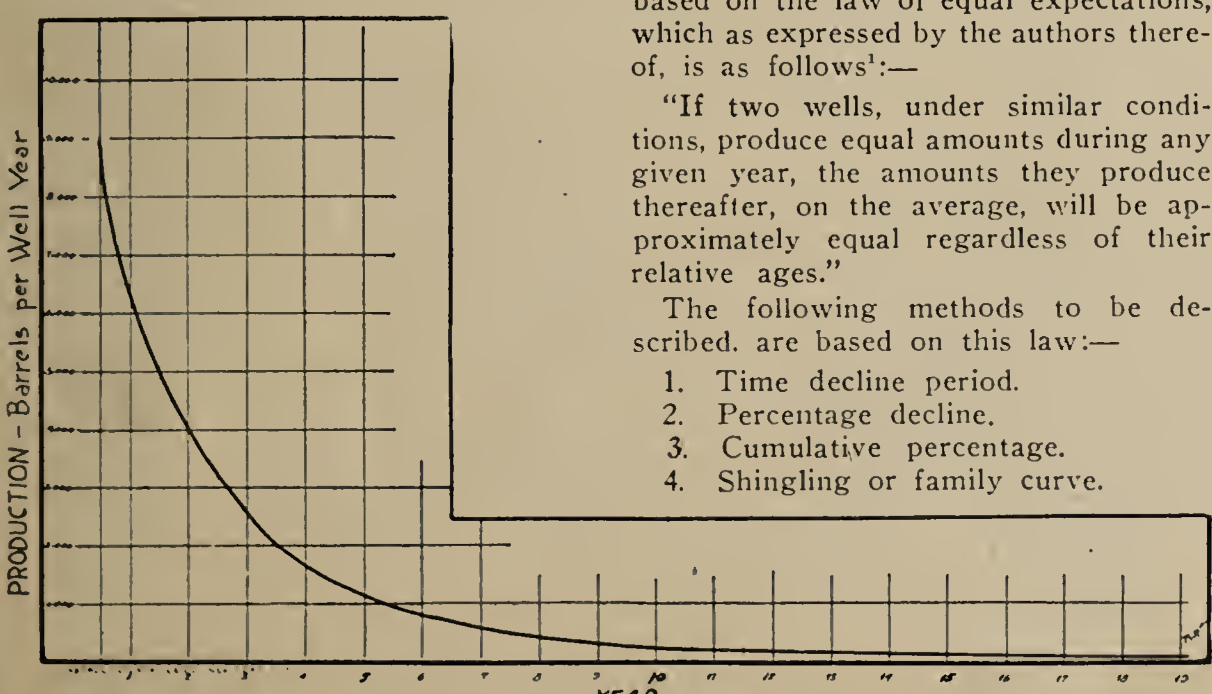

Figure 3—The composite decline curve from data in the table for Time Decline Period Method

To read future production, take the average per year prior to the date of estimate and find the point of intersection of the curve with the horizontal line representing the amount, thence one year to the right on the curve and read the first year's production, and so on for each year.

(2) **Percentage Decline Method.**—This method was developed by Carl H. Beal[4] and was first used by him in making composite curves of Osage County,

1—Lewis, J. O. and Beal, C. H., Some New Methods for Estimating the Future Production of Oil Wells: Am. Inst. Min. Eng. Bull. 134, Feb. 1918, pp. 477-504.

2—Johnson, Roswell H. and Roth, E. E., The Effect of Age and Size on Oil Well Decline Curves: presented at meeting of Am. Assoc. Petroleum Geologists, Oklahoma City, March 1920.

3—The authors have been authoritatively informed that this method was originated by Frank H. Herald, while assisting in gathering data and making decline curves of the Illinois-Indiana fields for the Manual of the Oil and Gas Industry of the Treasury Department.

Oklahoma, wells for the Bureau of Mines.

The production for each well the first year is called one hundred per cent, and each succeeding year is listed as a percentage of the first year's production. The curve is prepared from a table in which the percentages are arranged in relation to years from the first year. With the same wells already given in a previous table, the following tabulation was made:

age of the first year's production. The sum of these percentages to the economic limit gives the ultimate cumulative percentage.

To construct the curves, the ultimate cumulative percentages for the group or pool are plotted on rectangular coordinate paper, using a lower scale of average daily production the first year and a left scale of ultimate cumulative percentage per well. The points are plotted in scatter diagrams.

Tabulation of Data Showing Method Used in Computing the Composite Decline Curve by the Percentage Decline Method

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Well 1	100	41	27	15	12	7	5	2	4	2						
Well 2	100	42	12	7	7	6	6									
Well 3	100	60	31	21	20	12	10									
Well 4	100	82	63	55	43	45	37	30	30	25	21	17	17	16	15	14
Well 5	100	24	12	9												
Well 6	100	34	14	11	10	7										
Well 7	100	98	75	24	14	23	20	14								
Well 8	100	43	44	28	13											
Well 9	100	66	35													
Well 10	100	51	32	29	23	18										
Well 11	100	92	57	39	29											
Well 12	100	69	59	36	34	32	28	25	20	19	18	18	11	11		
Well 13	100	61	45	40	36	31										
Well 14	100	57	41	40	20											
Well 15	100	85	43	49	23	10										
Well 16	100	38	33	35	7											
Well 17	100	55	79	76	57	47	52	46	14							
Totals %	1700	998	702	505	348	238	158	117	68	46	39	35	28	27	15	14
No. Cases	17	17	17	16	15	11	7	5	4	3	2	2	2	2	1	1
Average %	100	59	41	32	23	22	22	23	17	15	20	18	14	13	15	14

Having found the average percent for each year, the next step is to construct a decline curve. Instead of production, a percentage scale is placed on the ordinate of the graph sheet and years on the abscissa. After plotting the averages found, it may be necessary to draw a smooth curve through the points.

As stated before, flush production is all in the same relative position on the curve. Since the annual future of any well is a percentage of the first year, all production is determined by using the consecutive percentages. Although the method is simple of application, it is objectionable, as the rate of decline in the early years varies so greatly with size. This is due to the omission of the age factor.

Cumulative Percentage or Appraisal Method.—The term "Appraisal Curve" is used by Beal[5] in the description of a new method, but was originated by him and Lewis[6] in an earlier publication. Since a conflict with "valuation curves" herein discussed is likely to arise, the term "cumulative percentage" is being applied.

The percentage decline curve previously described is used as the basis for the cumulative percentage curves. The percentage decline curves are made for as many properties as comprise the group or pool. Each curve is projected to its minimum economic limit. Each year's production is given as a percent-

The maximum cumulative percentage curve (see Fig. 5) is drawn so that nearly all points lie below it and the minimum cumulative percentage curve at the bottom of the diagram so as to bound the dots on the lower side. The average cumulative percentage curve is taken as a mean between the two.

From the production figures for the cumulative percentages, ultimate production curves are drawn. These facilitate the reading of future production, both as ultimate and annual amounts.

The points of the production curves are obtained by plotting the ultimate production figures for a number of wells of various sizes, as found in the above paragraph. The points are plotted on the same graph with the percentage curves, using the right scale of ultimate production, and the lower scale of daily production per well the first year, or the upper scale of first year's production per well.

It is to be noted that production so far is always obtained as ultimate, minimum, average or maximum, and not by annual units as desirable for analytic appraisal. To accomplish this, it is necessary to reverse the procedure taken in finding ultimate yield.

This method overcomes some of the objections to the percentage decline method in that the curves depend more on past performance. Where only a few properties are used, it might be advisable to give more weight to properties with many wells than those with only a few wells. This can be done by symbols alongside the points.

The chief disadvantage of the method is the enormous amount of calculation involved, the large number of wells required, and the personal equation. About sixty wells are represented on the diagram and still the personal equation is high.

(4) **Shingling or Family Curve Method.**—Where few wells are to be used, this method is most practicable. It was developed by Lewis and Beal to utilize their law of equal expectations.[7] The name "shingling" as well as "horse tail" is descriptive of the appearance of the graphs as arranged in this method. The results obtained approach most nearly those found by the "Time Decline Period Method." This is because the principles and execution are similar except that one is graphical and the other arithmetical.

The wells are first arranged in order according to size the first year. With

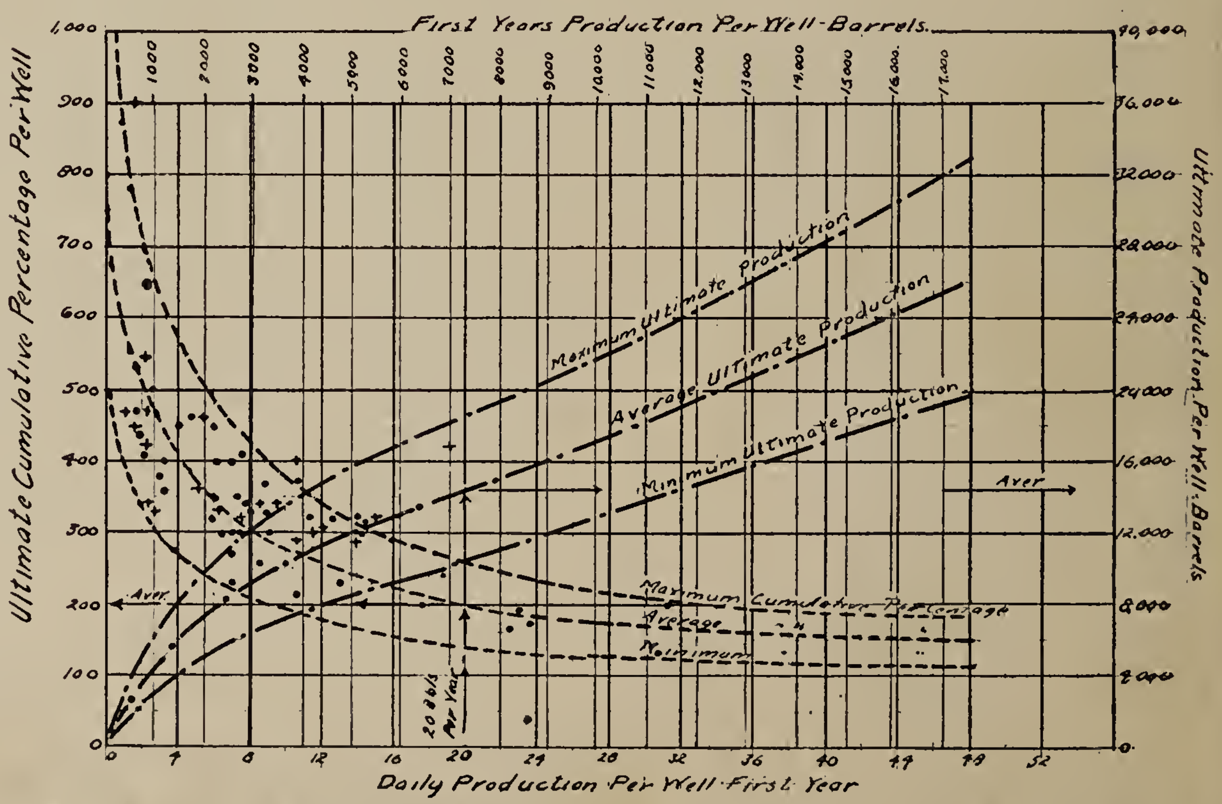

Figure 5.—Cumulative percentage curve of the Crawford and Clark county fields, Illinois. The dots represent the ultimate cumulative percentage per well of properties in the Crawford county field and the crosses represent the corresponding percentage per well of properties in the Clark county field. (After Beal)

4—Beal, C. H., The Decline and Ultimate Production of Oil Wells, with Notes on the Valuation of Oil Properties: Bureau of Mines, Bull. 177, pp. 29-30.

5—Beal, C. H., The Decline and Ultimate Production of Oil Wells, with Notes on the Valuation of Oil Properties: Bureau of Mines, Bull. 177, 1919, p. 30.

6—Lewis, J. G. and Beal, C. H., Some New Methods for Estimating the Future Production of Oil Wells: Am. Inst. Min. Eng. Bull. 134, Feb. 1918, pp. 477-504.

7—Lewis, J. O. and Beal, C. H., Am. Inst. Mining Eng., Bull. 134, Feb. 1918, pp. 499-500.

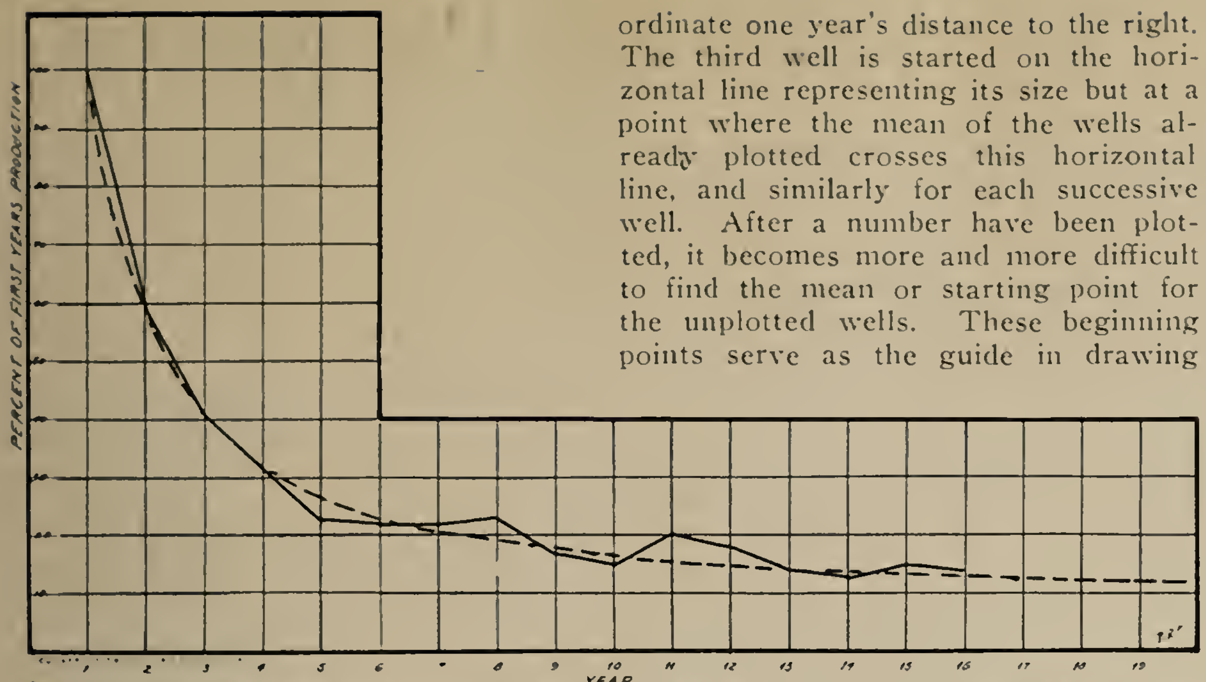

Figure 4.—The composite decline curve from the table for Well Percentage Decline Method

production on the ordinate of a sheet of co-ordinate paper, and years on the abscissa, each individual well is plotted on the sheet. The largest well is drawn in first, the second largest well curve is started on a point, the first well curve representing its size the first year. This ordinate point is the first year for this well and its second year is on the ordinate one year's distance to the right. The third well is started on the horizontal line representing its size but at a point where the mean of the wells already plotted crosses this horizontal line, and similarly for each successive well. After a number have been plotted, it becomes more and more difficult to find the mean or starting point for the unplotted wells. These beginning points serve as the guide in drawing the composite curve. If extrapolation is necessary the procedure outlined for the arithmetical method is followed.

Instead of taking the horizontal mean to find the starting point for the new curve, it is often found by taking the vertical average at a place approximately where the new curve is expected to begin and projecting a curve from previously ascertained average points through the last one found. The place of starting for the well to be attached is where the horizontal line representing its size the first year crosses this projection. The Oil & Gas Manual suggests this method of averaging.

In cases where some of the wells are aberrant and speed is essential, the median (the middle curve) or the "central tendency" can be estimated by eye. This is frequently more reliable than the calculation and especially so in the case just described, in which (see Fig. 6) well No. 4 appears to be abnormal and with so few wells being used it has an undue influence in the results, where the mean is used.

If the numerous decline curves are averages of groups of wells, weighting by the number of wells producing for each curve is essential to get accurate mean points for starting wells not yet plotted on the graph.

The error in the shingling method is the same as that for the time period method. It is slow of application when there are many curves to be combined. In fact, where the curves exceed nine, it is often necessary to divide them into sets and then make a shingling curve of the resulting curves. In other words, a two stage construction is used.

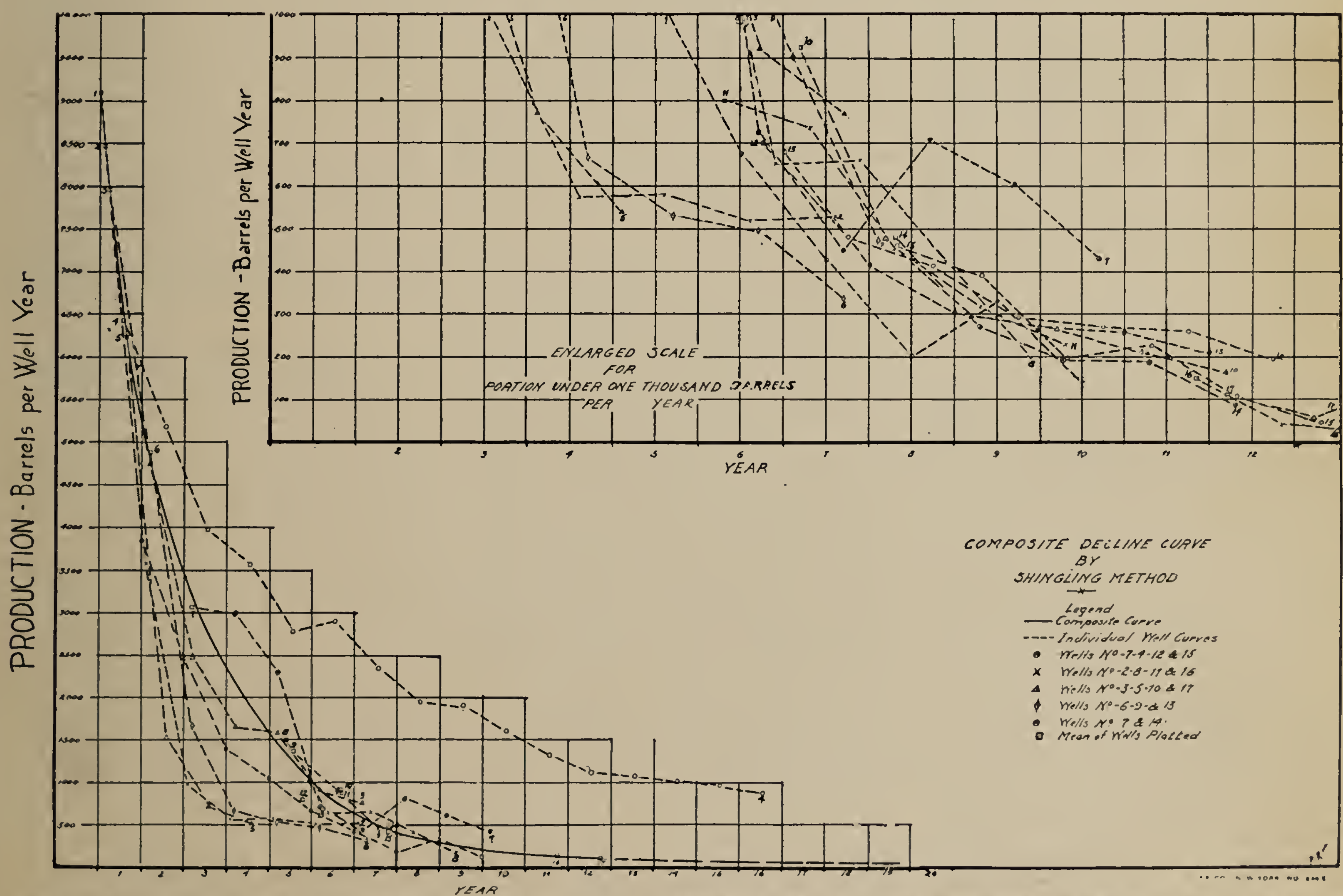

Figure 6—Construction of the composite decline curve by the Shingling Method. The horizontal means are used to get the beginning points for successive wells.

Appraisal Of Oil And Gas Properties

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Chapter VI (Continued)

Age-Size Method.—Of all the methods so far developed this approaches most nearly the degree of refinement essential for accurate commercial appraisal work. It deviates from the law of equal expectations in that age is a joint factor with size in the curve construction.

The first step which led to the method was devised by Willard W. Cutler, Jr., as described in the paper by the senior author and E. E. Roth.[1]

There are two steps; one the drawing of curves for each year's relation to the succeeding year, and secondly the final composite curves.

With the same wells used in the other methods, an attempt has been made to illustrate the principles.

On a large sheet of co-ordinate paper lay out scales suitable for the well sizes for the particular years. Both abscissa and ordinate are production scales. First a scatter diagram is made of the production the first year in relation to the second year. The points are connected in succession by a line and a smooth line is drawn so that the area to the right of the line and inside the points roughly equals the area to the left and inside the points. This is simply a means of drawing a weighted average line. Unlike the shingling curve, the larger the number of wells the better the method works. Each additional well involves very little work after the diagram is set up. The average line should not become vertical or take the reverse inclination as this woud indicate that wells too dissimilar have been combined to permit the construction of a composite curve.

By the same procedure, make a curve for the second year's production of each well to the third year and so on for each year. In the case illustrated ten years of suitable information was available.

For any given odd size of well, say 9775 the first year, its production for the second year can be read. With that figure, the production for the next year can be read and so on. From this a decline curve for such a well can be drawn.

(See Fig. 7, page 23)

A series of curves can also be drawn in this way on one sheet for wells having 10,000; 9000; 8000, etc., respectively in the first year.

The following table presents the values for the composite curve as read from the scatter diagrams in fig. 8.

Use of the Curve.—In reading future production for any well from this set of composite curves, find the point for the given age and size. For example, assume that a well produced 750 barrels per year, the year prior to the date of estimate, which was the third of its life. On the abscissa find the third year point, thence read up to a curve on or near the 750 barrel line. The production for the fourth year on the curve at this point will be the first for the appraisal. The fifth year will be the second, and so on. Instead of choosing the nearest curve, the results can be obtained by interpolating for the appraisal, by drawing a line between the converging curves above and below, keeping the proportional distance between them.

So far the age of the well above has been considered. Where the wells are all from one pool, then the age of the pool is ordinarily more important than the age of the well and should be used instead of well age, in the Age Size Method. In this case, where the number of wells (or leases) is quite large, it becomes possible to introduce another variable by segregating the wells into well-age classes. One can then read from a graph what a well making 9000 barrels in its third year, which is the fifth in the history of the pool, will do in its next year.

Rate of Production Curve.—[2] A daily production decline curve is called a rate of production curve. Such a curve may be estimated from any individual property's annual production decline curve, or from an average or composite production decline curve of a tract or pool.

A rate of production curve when used in conjunction with the annual production decline curve from which it was made shows the average daily production of a well at the end of its period of production, the position of which is known on the annual production decline curve; and conversely, it shows where a well whose average daily production at the end of a specified period is known should be placed on the yearly production decline curve.

1—Johnson, R. H. and Roth, E. E., The Effect of Age and Size in Oil Well Decline Curves: Am. Assoc. Pet. Geol., March, 1920

2—Cutler, W. W. Jr., Manual for the Oil & Gas Industry: Bureau of Internal Revenue, 1921, pp. 90-92.

Tabulation of Well Data from Preliminary Curves to Get Points for Composite Curves. Production in Barrels Per Year—Gross

Year		1	2	3	4	5	6	7	8	9	10
Composite Curve	1	9000	5100	3400	2480	2030	1575	1250	930	850	610
	2	5100	2800	1500	875	725	475	375	250	240	120
	3	2800	1500	775	475	350	250	200	130	100	90
	4	1500	820	440	280	200	170	150	120	100	90
	5	820	430	250	175	100	95	80	60		
	6	430	220	150	125	75	60	50	40		
	7	220	110	100	90	70	60	50			

The curve is advantageous where production for less than a year is given. The rate of production curve may then be used in order to place the well in its correct position on the average yearly production decline curve. Knowing the annual production, it is possible to estimate the future production from a curve or tables devised for the purpose. The daily production to be used in the application of the rate of production curve

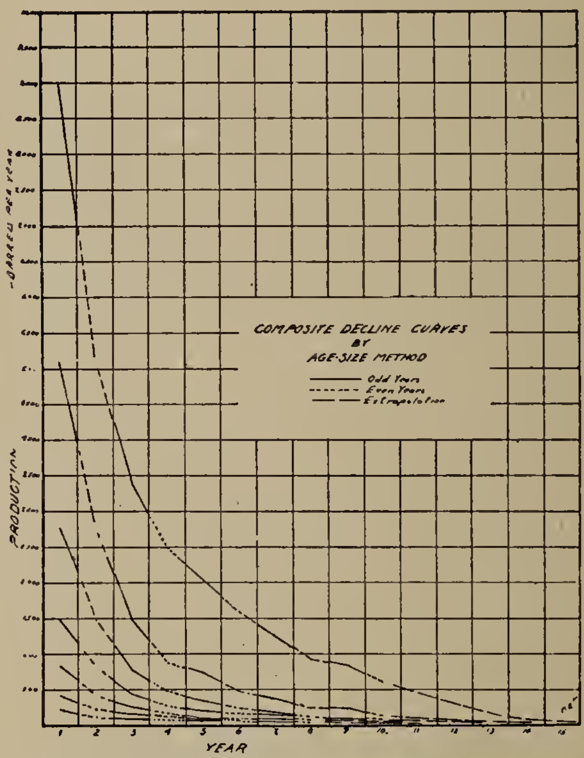

Figure 8.—A series of composite decline curves made from the preliminary curves in the preceding figure.

should be the average daily production of the well at the time the estimate of future production is made. Care should be taken in determining the present normal daily production to use a daily production which is free from all abnormal influences. It should be the average and consistent with the probable future practice in operating the well.

The use of the rate of production curve with a composite decline curve of a district should always be confined to those wells or tracts having production records so short or irregular that an undivided well decline curve or daily, weekly or monthly records, extrapolated to get data for an annual curve, is not accurate. The use of any average curve is likely to introduce into the estimates of future reserves errors which may be avoided by the use of curves formed from the production records of the wells of tracts under consideration.

A composite or average decline is a curve approaching a hyperbola and not a straight line. Consequently, the average rate of production for any year occurs at a time before the middle of the year. The greater the curvature, or the

rate of decline, the earlier in the year occurs the average daily production.

By dividing the annual segments of a curve into a number of equal parts, reading the ordinates of these equal divisions and averaging them, the time in any year at which the average daily production occurs may be found by plotting the average ordinate on the curve. The point on the curve where the average ordinate for a year intersects the curve will represent the time of year at which the average daily production occurs. The time of the average daily production for any year varies chiefly with the rate of decline. The following table shows the time in the year at which the average daily production for the year occurs, based upon the percentage of decline from the previous year.

Decline of yearly production from previous year.	Time before the end of year when average daily production occurs.	
Per Cent	Per Cent of year.	Date
0	50	July 1
10	51	July 26
20	52	June 23
30	53	June 19
40	54	June 16
50	55	June 12
60	57	June 4
70	58	June 1
80	60	May 24
90	63	May 14
95	66	May 3
97	69	April 22
99	73	April 7

Manual for the Oil & Gas Industry: Bureau or Internal Revenue, 1921, p. 91.

This table will locate the average daily production for the year at a point where the daily production is within 5 per cent of the correct average daily production for the year.

Construction of Curve.—To construct a rate of production curve for any district where a composite or average yearly production decline curve is available, move the yearly segments of the annual curve to the left, the distance indicated by the time in the above table.

This may be done on either quadrille or logarithmic paper.

The same horizontal scale representing time is used for both of these curves. The vertical scale representing barrels per year is divided by 365 in order to provide a production scale for the rate of production curve so that any line representing production in barrels per year will also represent the corresponding production in barrels per day.

Any point on the rate of production curve represents the last day's production for the annual amount shown on the average or composite decline curve vertically above.

Individual Well and Property Curves—In any appraisal where the oil well production is available for a sufficient period, the calculation of future yield should be directly the basis of this information. Composite decline curves built up from other properties are averages, and are not to be used indiscriminately when valuing an individual well or tract. The extrapolation of information pertaining to the particular tract or lease will ordinarily give a closer estimate of reserves than an attempt to estimate it from an analogous composite curve.

The installation of gas, vacuum or compressed air pumps often increases the rate of production for a short period, and then decline again sets in. The methods do not seem to hasten the end of the life of the wells but merely increase the ultimate recovery by the amount of production yielded above that if the installation had not been made. The persistence is generally nearly the same in the segment of the decline curve following the rise in production due to forced pumping, as the one representing similar rate of production at a period before the application of the forced pumping.

A graphic method for finding future reserves on an individual property is shown in Fig. 9. The smooth curve is not begun until after most of the flush production is off. This method of extrapolation requires careful consideration as the personal equation is large and variable results are easily obtained.

Curve for a New Well in a Previously Unproductive Region.—The future production of a new well in a previously unproductive or untested region is of course especially difficult to estimate. If the well is operated to capacity daily for a number of days and careful production records are maintained of the results some idea may be gained of its possible rate of decline and future reserves.

The most feasible means for making the calculations is to plot the daily production on co-ordinate paper and to draw a smooth curve between the points; but

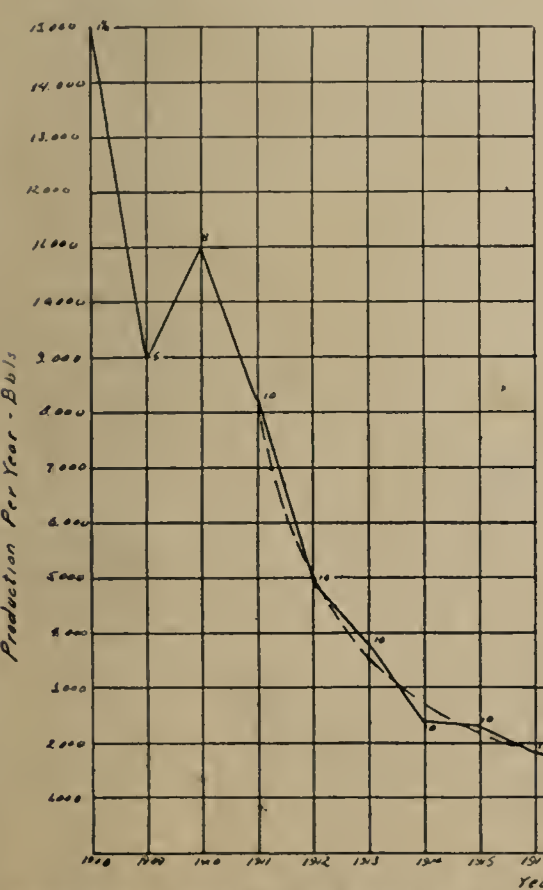


Figure 9.—Curve of average production for an individual lease with extrapolation of future yield. Numbers indicate numbers of producing wells.

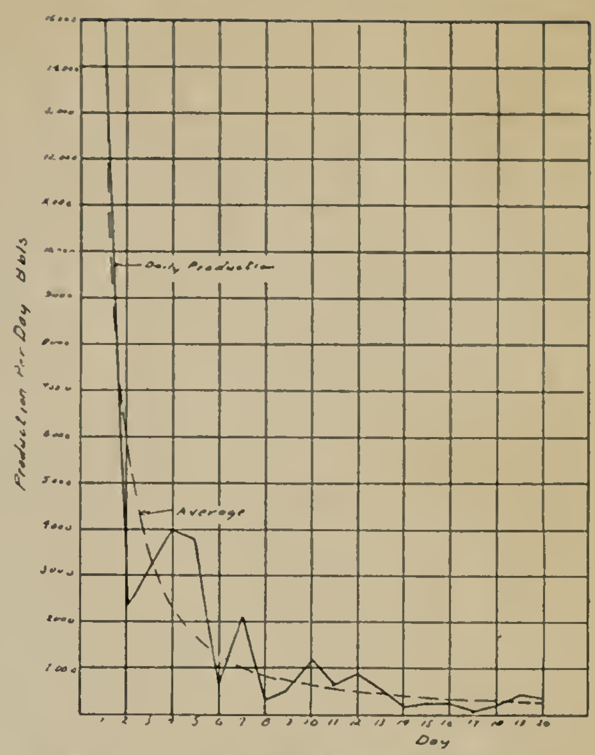

Figure 10.—Chart showing an individual well daily production curve and the average curve (dashed line) drawn preliminary to transferring of data to logarithmic paper for extrapolation.

do not project it. Then transfer the end points of the curve, and at least one more, to logarithmic paper, and by shifting to the right or left get the points arranged in a straight line. By extrapolation find the daily amounts for as many days as possible and by additions obtain the weekly, or preferably, the monthly production for at least three weeks, or three months. These results, by replotting against a weekly or monthly scale, whichever it may be, can be further projected to get the yearly totals, for at least three years. Again replotting, this time with the yearly totals, a postulation of ultimate production, or if desirable the annual units thereof can be made. Figure 10 on this page and figure 11 on page 22 show the procedure mentioned.

This process is not always reasonably accurate but if carefully done should be sufficiently reliable as an observation of rate of decline and to use in contingencies as the basis for appraisal.

Daily or Monthly Rate to First Year.[2] — In the study of young wells it becomes necessary to utilize shorter time periods than a year. The most valuable relation to ascertain is that between either the initial (the production of the first 24 hours), or the first month's production and the production of the first year. Both curves can be plotted on one graph as in Fig. 12.

In the illustration there is given the first year's production on the abscissa and either or both the first day's or the first month's production on the ordinate. The dots are entered, making a scatter diagram. A curve is then drawn through the central tendency or the location of

2—The daily Rate to First Year's Production Curve was developed by C. H. Beal in "The Decline and Ultimate Production of Oil Wells, with Notes on the Valuation of Oil Properties": Bureau of Mines, Bull. 177, 1917, p. 59. G. H. Alvey later described a similar curve based on monthly rate to first year's production in "Decline Curve Predictions from the First Day and First Thirty Days:"Am. Assoc. Pet. Geol. Vol. 4, No. 2, 1920.

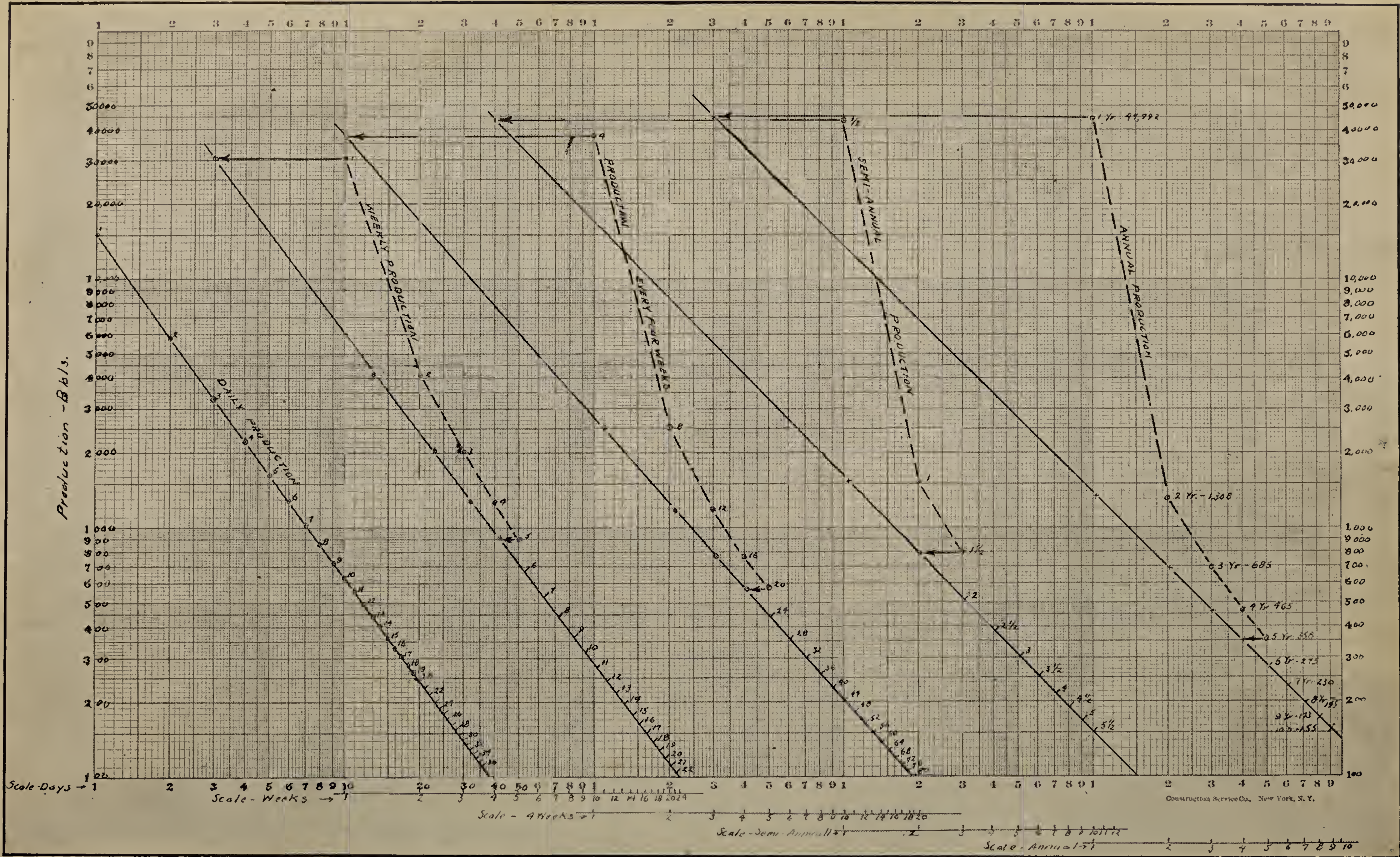

Figure 11.—Chart showing projection of daily production line to give weekly production and of the weekly production line to give production every four weeks, etc., until finally a curve of annual production is obtained. Broken lines are first plotting and solid lines the position of points when in a straight line

greatest density of distribution of the dots. The month-year relation has a very much lower probable error than that of the day-year and should be used in preference where possible. From the initial production or the first month's production the barrels the first year can be read from the curve. The remaining future yield can be calculated from the composite decline curve for the pool, using the first year's production estimate as the starting point.

Economic Limit.—This term, as defined in the Manual for the Oil and Gas Industry, is "the smallest production per unit of time at which a well may be operated profitably." There is considerable latitude in the words "operated profitably" since the cost is incurred for a lease in the main part and the lease has some wells which are larger than those in question. Many producers therefore permit some wells to continue pumping past a point which would be the economic limit, if all the wells on the lease were the same size. Such a practice is sound within limits. For most calculations the economic limit will be taken on the assumption that the wells on the lease are equal. Gas wells have a more definite limit in the fixed annual rental which is its largest element of cost and is definite.

The "Economic Limit" is a feature that has come in for considerable study by those concerned with the more commercial phases of appraisal work. Since such appraisals have to do frequently with consolidations of interests which

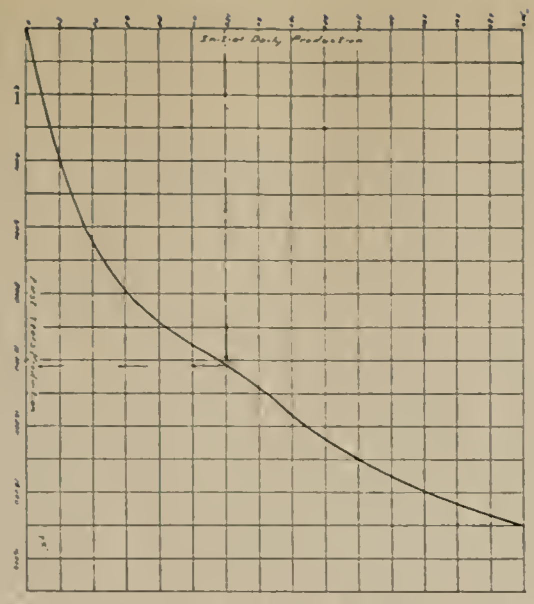

Figure 12.—Curve for finding the first year's production from initial daily production for the Clinton sand, Ohio.

have hitherto been operating independently in the same field, or with a situation where one company is actually purchasing the property of a neighbor, it is often necessary to go beyond the bare facts as to the apparent economic limit at the time of the review, in order to determine a new limit that will result from a change in the operating conditions. The important features to be considered are:

Probable future operating costs.

Probable future price of oil or gas.

As the economic limit is approached some wells will be abandoned as unprofitable. The continuance of others will involve the study of that portion of operating expense which is fixed, namely supervision, accounting, interest, and other charges which continue independently of any one or set of wells.

The Co-ordinates of Production Decline Curves.—The custom of describing a decline curve by giving the co-ordinates of two points on the curves when it has been so placed on logarithmic paper as to be most nearly straight has been recently introduced by W. W. Cutler, Jr.,[3] and is very useful for briefly describing curves. The co-ordinates of two points then definitely establish the persistence factor for the curve. The points $X_1 = 3$, $Y_1 = 3200$ and $X_2 = 15$, $Y_2 = 175$ if plotted, and a straight line drawn through them, would reproduce the decline curve. The x ordinates in this case represents years and the y ordinates the production for the respective years. A tabulation of the co-ordinates expressed in this way for nearly every field in the country is given in the appendix.

Designation of Spacing of Wells with Decline Curves.—It is highly important that the average acreage per well be known for those composing the composite or individual property decline curve. These data will aid in making predictions where a change in operating practice is anticipated in this respect. Furthermore, this information would be a valuable guide in calculating reserves on undrilled locations. It is unfortu-

3—Manual for the Oil and Gas Industry; Bureau of Internal Revenue, 1921, pp. 79-84.

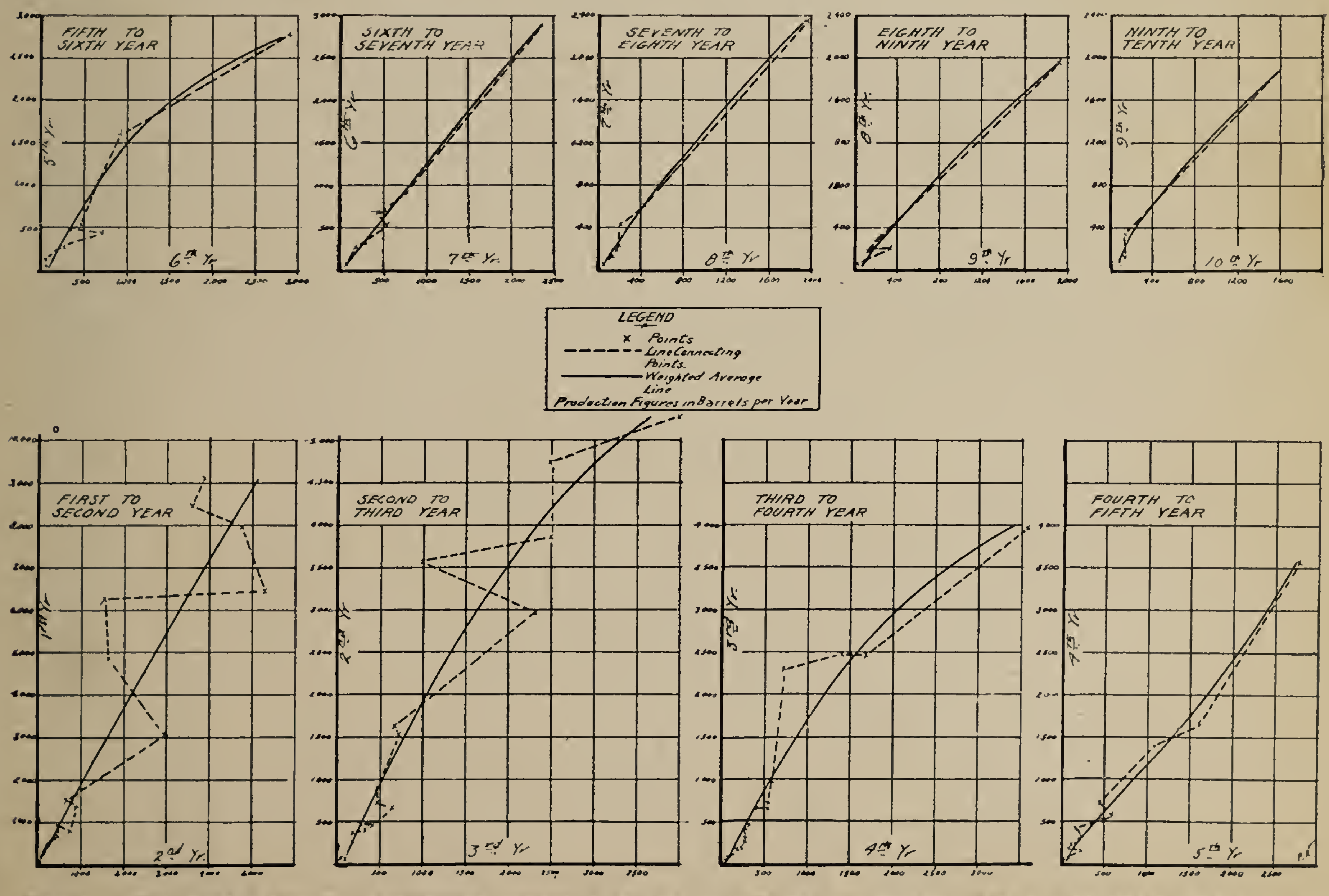

Figure 7.—Preliminary step for constructing composite decline curve by age-size method. Scatter diagrams are made of the relation of production each year to the following year.

nate that this is lacking in so many of the curves published by the Treasury Department.

Estimation of Future Yield by Computation of Voids.—In the past, many engineers made calculations of oil reserves by estimating the amount of voids in the producing sand and the probable saturation and recovery. In the case of natural gas, this method requires a further assumption, that of original closed pressure on the basis of depth and most analogous fields.

The general formula for oil is as follows:

Area of pay X thickness of pay X % effective porosity X % containing oil X % recoverable = recoverable reserve.

For gas the general formula is:

Area of pay X thickness of pay X % effective porosity X

$$\frac{\text{lbs. absolute pressure} - \text{pressure at economic limit}}{\text{atmospheric pressure} + 4\text{ oz.}}$$

X % recoverable = recoverable reserve

Taking up these items seriatim:—(a) the area of pay will ordinarily be the number of wells, it is estimated it will pay to drill, times the estimated acreage per well in the spacing program planned. Strictly speaking there is probably an addition of peripheral territory contributing some oil to the edge wells although not enough to warrant further drilling in its direction. In practice this will ordinarily be considered as compensating the deficiency of the area drained which is assigned to the edge wells.

(b) The thickness of pay determination is subject to a probable error so high that the method itself cannot be expected to give good results. Without a core drill the thickness cannot be well measured, nor can there be a proper deduction for thickness of non-pay strata included in the general pay, as complete cores are uncommon except in a few districts. Even where a core drill is used the sand may be so soft as not to make a good core. Supposing that a good core could be had, there would still be an error, since the pay would vary in thickness between the wells, and in the amount of interbedded non-pay.

(c) Some of the pores of a pay are extremely small and others are so blocked off as not to be drainable at the pressure differences met in the field. Determination of effective porosity by a method of introducing or removing fluid is therefore to be preferred to the common one of absolute porosity. When only absolute porosity figures are given they should be reduced to an estimated effective porosity. A. F. Melcher, of the United States Geological Survey, now has some experiments under way that will give a better idea of the relation of these two values.

(d) The percentage of the effective voids containing oil called by Washburne[4] "saturation" has unfortunately been given very little study so that no satisfactory determination can as yet be made. It would seem better in most cases to ignore this as a separate factor and let it be included in the percentage recoverable where some data at least are available.

(e) The percentage that can be recovered is so variable as to constitute another weakness of this general method. The best data available are those of Chambrier which show that only 17 % of the actual total oil at Pechelbronn where exhausted oil sand has been mined had been obtained by the wells. Since recoverability is a function of fineness of pore space, original pressure, viscosity and amount of dissolved gas (and still other variables) one dares not use this determination widely.

Any estimate of future reserves by this volumetric method has so high a probable error that it is only to be used in rare circumstances and then along with the usual method of analogous performance records. It cannot give a satisfactory appraisal as it does not give the rate of recovery which is needed for proper appraisal.

4—Washburne, C. W., Estimation of Oil Reserves: Trans. Am. Inst. Min. Eng., Vol. 51, 1915, pp. 648-9.

Estimation of Future Reserves for a Field or Pool.—The calculation of probable recovery from so large an area as a pool or field can only be made in a general way. Such information is seldom required for an appraisal but is in great demand when the trend of the market is to be analyzed.

The information as to initial well and pool production and number of wells is usually available from one or more of the various oil journals or papers and the U. S. Geological Survey. In comparatively new pools, the data may be entirely lacking or not yet completely compiled.

Each pool's history will show that one of the following conditions is evident:

1. Rate of production is increasing.
2. Rate of production is decreasing.
3. Rate of production is constant with a probable increase or decrease in rate.

With any of the above, there may be a rate of drilling as follows:

1. Increase in rate.
2. Decrease in rate.
3. Constant rate.

The combination of the two groups applying to the pool under examination will determine, in a large part, the procedure to be used in getting future yield.

Any estimation of reserves can be roughly made by considering the items in this outline:

1. Draw a composite decline curve for the pool.
2. Find average production per well and by the composite decline curve the future yield for such a well and hence the total for all the wells producing in the pool.
3. Find the curve of decline in initial production.
4. Find the rate of drilling and postulate the number of wells each year until the pool is fully developed.
5. With the initial production curve and (4) get the total future reserves for all the wells to be drilled each successive year and add to the results in (1) to get the grand total.

5—de Chambrier, Paul, La Source de tional, Bulletin de Juillet-Aouit 1920, p. 4. Petrol Jaillisante de Pechelbronn: Societe d'Encouragement pour l'Industrie Na-

Appraisal Of Oil And Gas Properties

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Chapter 6 (Continued)
Gas

WITH a variety of types of production estimate tests to choose from the appraisal engineer has the task of choosing the most reliable and feasible test or combination of tests to use in estimating future reserves. Commonly a gas company, however, has only one kind of test of sufficient frequency to use for calculation of future yield. After having chosen the readings to be used the important decision of selecting the best method of constructing decline curves remains.

Closed Pressure Tests.—To obtain a closed pressure reading of a well, it is first closed in. The time necesary to build up to a condition of substantially uniform pressure in the area surrounding the well depends upon the character of the sand, the situation of the well with reference to other wells, the limits of the pool, water conditions and other factors. There are numerous other factors bearing on the result that should be recorded, such as length of time closed in; proximity of other wells and whether these are also closed in; depth of well; diameter of tubing; line pressure when well is flowing and line pressure when the given well is closed in. If the well promises to build up larger than the time convenient to close in for a test would permit, successive tests with time of each, if charted, should give a curve such that a fair estimate could be made from it as to when the built up pressure would be attained.

Relation of Closed Pressure Tests to Production. It is the opinion of some men that there is no usable relation between closed pressure decline and production decline. It is of great importance to study this relationship, since the closed pressure decline curve is easily and cheaply kept and is often the sole data. Three conditions may exist:

(1) Relation between closed pressure and production approaches theoretical case and follows Boyle's Law of Gases namely, volume is inversely proportionate to pressure.

(2) Relation between observed closed pressure and observed production is not in accordance with Boyle's law but to an ascertainable extent deviates, because of interference by some one or more variable.

(3) Relation between closed pressure and production is so complex because of the variables found in (2) as not to leave any feasible method of use.

An examination of about 30 pools in the Appalachian field was made to determine what relation exists. In no case was the volume recovered in the successive units of time inversely proportionate to the pressure during those time units. In two pools the relation approximated the law in the early life of the well but showed an increasing devia-

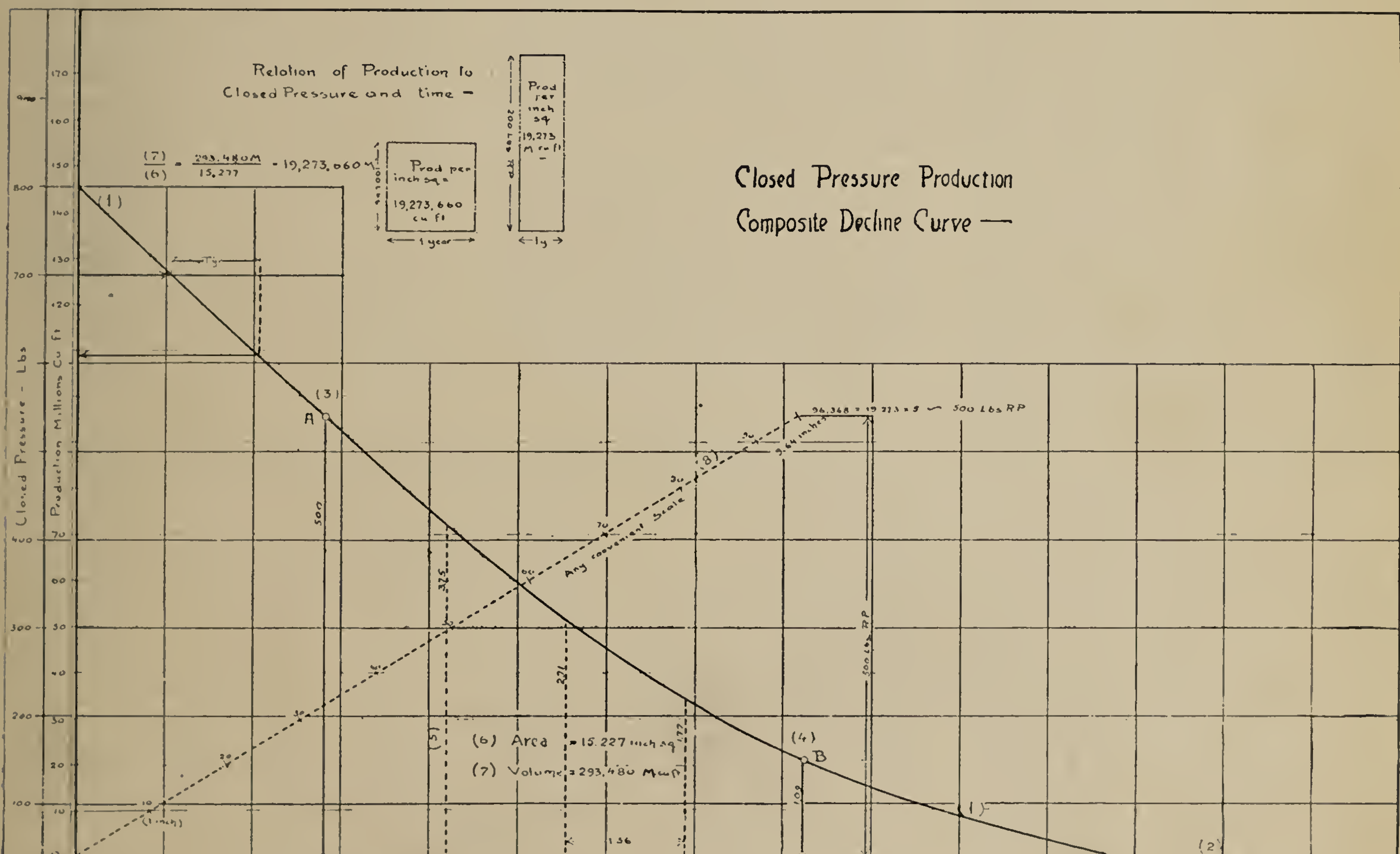

Fig. 13—Construction of Closed Pressure-Production Composite Decline Curve

(1) Closed pressure composite decline curve;
(2) Line of Economic limit;
(3) and (4) beginning and ending closed pressure points of average well;
(5) One of ordinates for area Calculation;
(6) and (7) Area in square inches of ABCD and volume in M cubic feet of average well;
(8) Line for fixing scale of production on left ordinate of graph. (After Ruedemann and Gardescu)

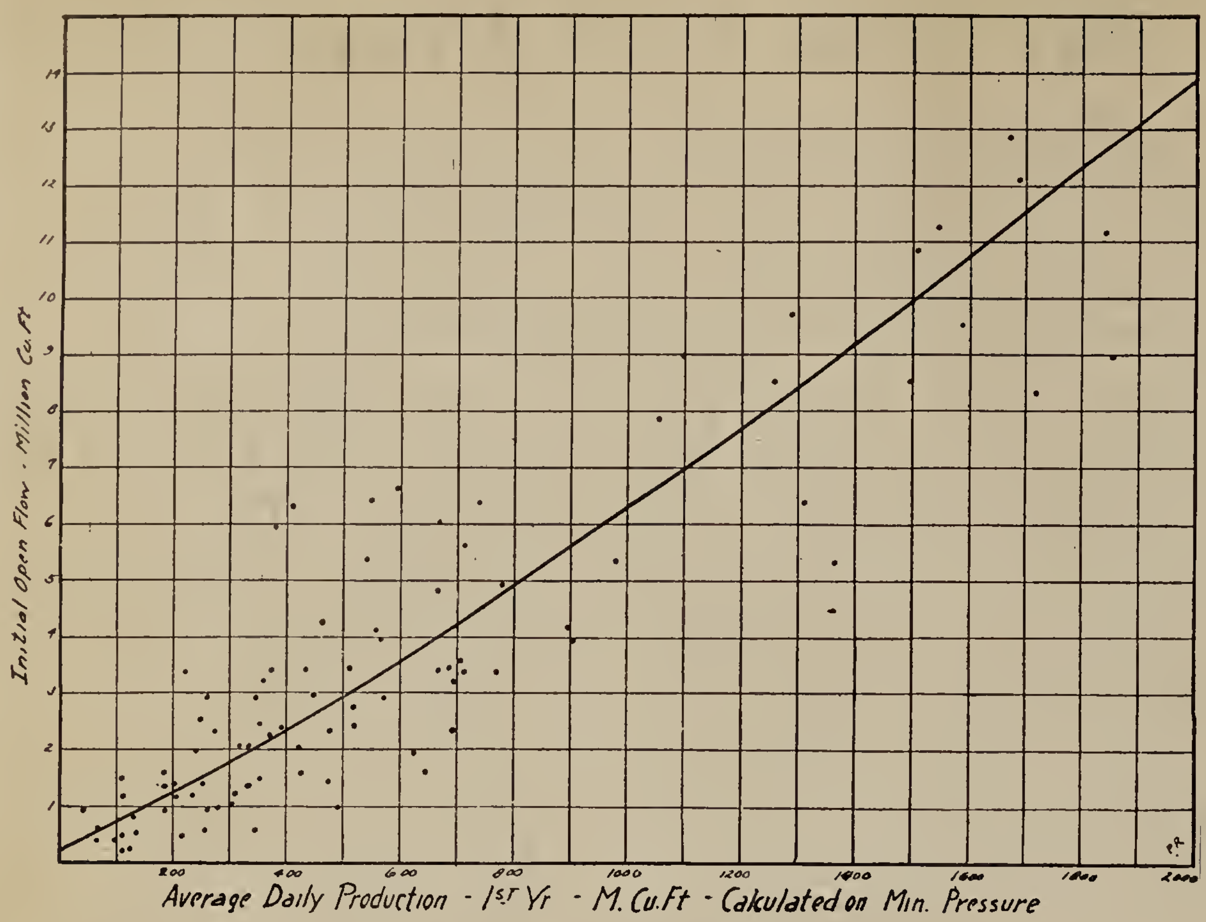

Fig. 15.—Chart for finding average daily production the first year when given the initial open flow capacity. Curve for the Clinton sand, Ohio

tion as the closed pressure declined below about 300 pounds. When a study is made of the natural conditions which may affect the theoretical application of the law it is evident why such deviations may occur. Some of these are:

(1) A gas reservoir is not a closed container with a definite, clear-cut surface. There is a transitional peripheral zone surrounding the part of the reservoir which permits the freest flow. In the least porous and most distant portions a decided pressure differential is requisite to produce any important flow.

(2) Pressure in reservoirs is not uniform. When a well is flowing the pressure is least nearest the hole and increases with distance to a point where interference from other wells is effective and causes a decrease. One of the conditions necessary to the use of Boyle's law is uniform pressure throughout the container.

(3) The presence of water in the sand and contiguous strata decreases the ultimate yield. Encroaching water frequently shortens the life of a well. A small pool in Oklahoma entirely controlled by one company showed that the economic limit could be predicted for each successive well on the structure by the rate of water advancement. In this particular instance each 10 feet higher on the dome gave about 30 pounds lower closed pressure economic limit. Lack of water in the producing and surrounding strata may account for an increase in production per pound less with the age of the wells.

(4) A uniform temperature must exist to produce the ideal decline by Boyle's law. The principal temperature deviation arises from encroaching water. This deviation is slight so that this factor alone is of little consequence.

(5) There is a certain amount of leakage into non-producing sands. The amount, if constant, would not affect the relations, but this is not the case, as it changes degressively as the pressure in the receiving sand increases. Deterioration of casing with age probably permits more leakage in later than in earlier life.

(6) Gas flows against a pressure in the line which is generally variable. Sometimes the line pressure is inadvertently allowed to even exceed the well pressure and gas is returned to the well, whereas the record indicates a production. Where such a situation is likely a check valve is usually installed.

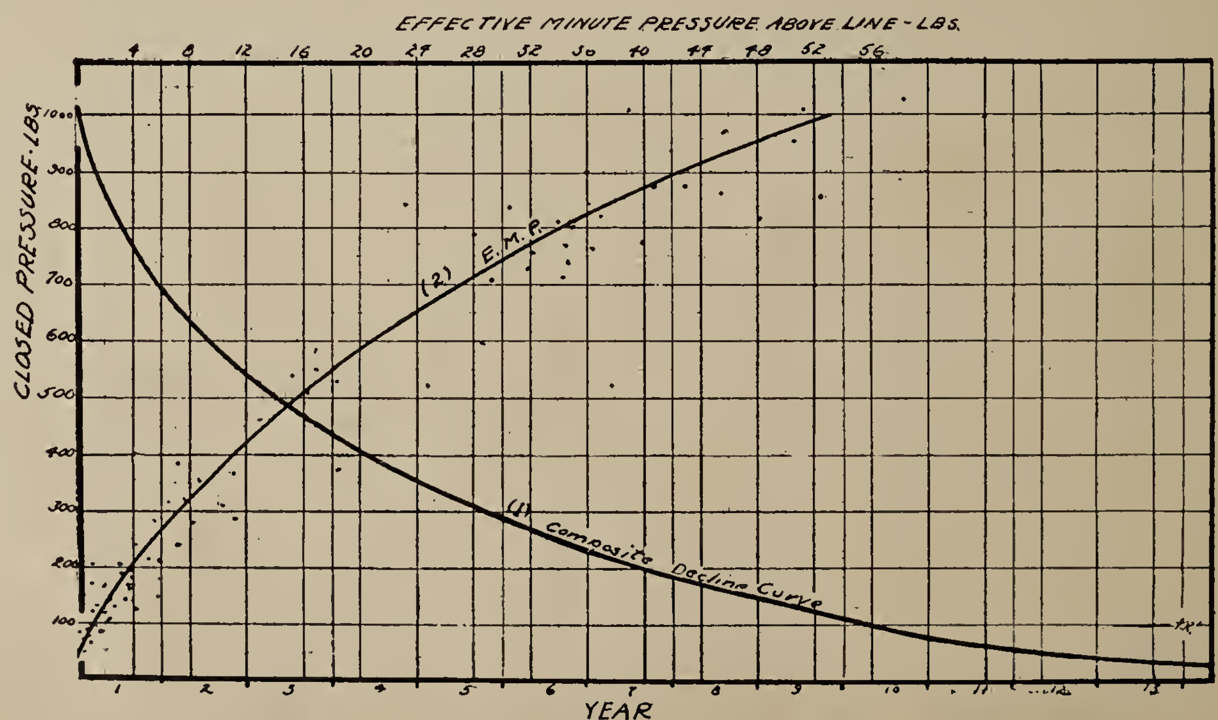

Fig. 14.—Curves for estimating future production by a closed pressure and effective minute pressure above line relation. (1) Closed pressure composite decline curve and (2) curve of average effective minute pressure above line

(7) Wells on vacuum, provided there is no water encroachment, generally yield excessively for each pound of loss. This is probably the result of draining the peripheral zone of the reservoir which yields very slowly.

(8) Natural gas[1] does not act as a perfect gas in the meaning of Boyle's law even under laboratory conditions.

(9) There are pools where the gas is provided from a group of lenticular bodies of sand, instead of from one reservoir where a greater or less degree of continuity exists. Even where such sands are situated within fairly well-marked zones, the closed-in pressures vary widely, and volume-capacities of individual wells against differing line pressures have a wide range. In these cases the determination of probable reserves may prove extremely unreliable if pressure data alone are considered.

Other variables of lesser importance exist. It is evident that the variables are numerous and not constant. If they were constant, correction factors could be computed and the exact relation of closed pressure to production estimated. With so many variables the individual wells cannot be handled with the same assurance of accuracy in gas as in oil. The action of one or more wells may give an indication of what to expect on the average, but the accuracy of ultimate reserve estimation increases with the number of wells in a pool taken to compute the average.

Bureau of Internal Revenue Formula for Computing Depletion Allowance in Closed Pressures. The Bureau of Internal Revenue recommends a formula for the computation of depletion allowance which is based on Boyle's law. The depletion is estimated in units of pounds decline. The formula is as follows:

Capital Sum to End of Taxable Year.

Sum Pressures Beginning of Year+Sum of Initial Pressures of New Wells, —

1—Burrell, G. A., and Robertson, I. W., The Compressibility of Natural Gas at High Pressure; Bureau of Mines, Technical Paper 131.

Sum of Pressures at Expected Abandonment.

$\times$

Sum of Pressures at Beginning of Year + Sum of Initial Pressures of New Wells Minus Sum of Pressures at End of Tax Year = Depletion Allowable.

This formula assumes equal production for equal decline in closed pressure. Being in closed pressures it is not a function of production and is likely to result in unfair treatment. Also, no provision is made for reserves on locations. A company with a tract large enough for many gas wells may deplete the total capital account before the tract is drilled up. The first few wells may be completely exhausted before the remaining wells are completed. The depletion is taken on the decline of producing wells only and consequently the portion of capital account attributable to the non-producing part of the tract is erroneously depleted by the producing part. Provision is made for this contingency in oil property depletion by requiring an estimate of all the reserves irrespective of number of producing wells at the end of the last taxable year.

Following the assumption of Boyle's law as applied to natural gas production decline, an estimate of future reserves remaining as of any date, can be made. The computation is:

$$\frac{\text{Total Production Recovered to Date from Pool}}{\text{Total Pounds Decline in Pressure to Date of All Wells Used in Numerator}}$$

= Production Per Pound Decline.

Production per pound decline $\times$ (total pressure remaining in producing wells minus total abandonment pressure) = reserves remaining underground for producing wells.

Where the properties are not fully developed and total reserves on the whole acreage is desired the last part of the computation changes to: Production per pound decline $\times$ (total pressure remaining in producing wells plus total anticipated initial closed pressure of locations minus total abandonment pressures) = reserves remaining underground on whole acreage.

Estimation of Future Yield By Open Flow Capacity Tests. The estimation of recoverable reserves by these tests is probably the most expedient and, from evidence so far produced, is reasonably accurate if properly executed.

A relation to the rate of decline of production is apparent. The tests are volume production against atmospheric pressure and are consequently taken with less variables than other volume tests. Nevertheless, much error creeps in from various sources.

Estimation Future Yield by Minute Pressures Above Line Tests. In this method a gauge reading of the line pressure is made, then by shutting a gate the reading for the first minute, and frequently others up to about twenty minutes, is observed. The difference between the first minute reading and the line pressure is considered the effective minute pressure. The effective minute pressure times volume of the well, with adjustment to standard meter, gives the flow per minute.

Under certain conditions the tests have little value in estimating reserves. Changing line pressure frequently creates the condition of similar effective minute pressures for a period of many years. This depends upon the time the well is turned into the line.

Construction of Decline Curves. The methods proposed for use in calculating future yield for oil wells are all applicable to gas wells whether the metered yield, open flow, or minute pressure above line readings are used. However much the law of equal expectations may fail to apply to oil wells, it surely applies less to gas wells for the following reasons: (a) At any time the performances of a well is so greatly influenced by the "pull" which it has had for the preceding month or so that it may appear much better or much worse than it would under ordinary conditions; (b) a premature abandonment because of water encroachment, which would cut down the future production from the expectation, is much more common in gas wells than in oil wells; (c) drainage is effective from so much greater distances that interference from other wells drilled later is greater; (d) flow from the low grade bordering rocks of the reservoir may contribute a great deal of gas and greatly prolong the life, or it may be absent because water fills these rocks. Because of the freer flow of gas the pressure factor is much more important relatively in the gas well than in the oil well flow. As pressure is directly affected by age, it makes the role of age too important to ignore.

The age-size method has therefore still greater advantages over the other methods based on the law of equal expectations in gas wells than in oil wells. But here also paucity of records may force the use of the older methods.

While monthly curves can often be used in the study of new oil wells, the vicissitudes of gas wells are so much greater and the seasonal variation is so important that any curves by monthly production are generally too irregular for use.

Corrected Curve. Since the estimates of gas flow by tests, except meter, are not accurate, a correction factor must be applied to get the production likely to be found if meter tests were made at the wells. The correction can either be applied to the curve or in the calculation of production prior to plotting the points for the curve, or after obtaining reserve estimates.

The corrected curve will usually be below the composite curve as the calculations are generally in excess of the actual amount. To obtain the curve reduce several points on the composite curve by multiplying by the "field reduction factor." Having plotted the points draw a new curve. In reading the annual production amounts, or part thereof, use this curve, starting, however, on the original curve as it is made up of the type of reading used as a basis for the determination of the well's size.

As a rule, it is preferable to correct the calculated production estimates by the field reduction factor before plotting the curve. However, it is well to have both curves shown on the same sheet to give the greatest usefulness and avoid the calculation otherwise necessary to get corrected well size.

In the Percentage Decline Method a correction curve is impracticable and consequently the correction must be made before computation of the table for getting the averages or after the readings are made from the curve. In any event the choice of the correction method depends largely on the labor saved.

Estimation of Future Yield by Closed Pressure—Production Combination.[2] It has long been recognized that closed pressure bears some relation to production. For want of more definite information it has been assumed that production is approximately proportionate to decline in pressure. This is the conclusion taken by those using the formula for depletion promulgated by the Bureau of Internal Revenue. In this formula, the percentage of decline is in terms of the amount of total pressures at the beginning of the year. It works much on the order of depreciation on declining values. If carried out long enough, it is found that depletion or production is actually assumed as proportionate to decline in pressure. The Manual for the Oil & Gas Industry admits fallacy in the assumption and mentions certain refinements possible but ends by stating, "These two considerations (referring to refinements), have a tendency to balance each other and, with certain exceptions, will not be of sufficient importance to warrant an attempt to apply the corrections."[3] The basis of the method is Boyle's law. Depletion on decline in pressure is in disregard of the units of production extracted during the period. The problem should be approached properly from the facts rather than from an assumed law. Two methods will be discussed, one based on "areas subtended," and the other a purely empirical method.

The principle on which the new curve is based is that the areas beneath segments corresponding to closed pressure decline are proportionate to the amount of gas produced. All references to the outlining of the method are to Fig. 13 and are taken up in the order necessary to construct the curve, which is:

1. Closed Pressure Composite Curve.
2. Line of Economic Limit.
3. Average Beginning Closed Pressure of Wells.
4. Average Final Closed Pressure of Wells.

2—Ruedemann, D. and Gardescu, I. I., Estimation of Reserves of Natural Gas Wells by Relationship of Production to Closed Pressure: A. A. P. G. March meeting, 1922.

3—Bureau of Internal Revenue, 1921, p. 35.

5. Vertical Distances.
6. Area Computation.
7. Volume of Average Sand.
8. Line of Scale Computation.

1. Closed Pressure Composite Decline curve.—This curve is nothing more than the usual average or composite curve of a number of wells. The method of constructing this is optional with the engineer. A number of recognized ways are in common use, as previously discussed. Some are not practicable because of the nature of closed pressure decline rate. The junior author has obtained the most satisfactory results by using the so-called Time Decline Period or Segmental Method.

In the particular example given, the closed pressures of each individual well were plotted in relation to the time taken for decline. The points were generally irregular and necessitated smoothing out by an average curve in a few cases. From the individual curves was read the time of decline from one closed pressure to another.

2.—The Line of Economic Limit. This depends upon the history of abandonment. In the particular case shown, the wells in the region had been abandoned, on the average, at forty pounds closed pressure. It is quite possible that in the future, when pumps are more generally installed, a much lower average will result. Where such is likely to occur, the line can be lowered to the probable average future pressure abandonment. Since no production takes place below this line it is considered the line of zero production.

Instead of a horizontal line of economic limit a vertical line can be drawn at the intersection of the point where the closed pressure curve intersects the forty pound pressure line. It was found that the former was the more convenient and accurate method.

3.—Average Beginning Closed Pressure of Wells. For all the wells used in the construction of the composite decline curve, the beginning closed pressure is listed and the average found. Since it is necessary to have production for the period corresponding to closed pressure decline of each well, the readings do not all go back to initial pressure. The average herein was 540 pounds, or 500 pounds above the line of economic limit. The 540 point is indicated on the composite curve as the point of beginning of the average well.

4. Average Final Pressure of Wells. —This is the average of the last readings used for all wells included in the composite curve. It is not necessarily the reading as of the last date available, for production must be given, and consequently the last reading used for some wells is not the most recent. The average was 149 pounds or 109 above the economic limit. The point is marked on the curve as in the case of the beginning closed pressure.

There is now given the average beginning closed pressure, the average final closed pressure and the production for the period. The production is given for the average well and for the time indicated by the average decline. For purposes of refinement it is often desired to find the production for the average sand, instead of the average well. All data for this curve is reduced to one sand.

5. Vertical Distances.—The beginning and final vertical distances are mentioned in parts (3) and (4) above. The others depend upon the division of the area for the purpose of calculation. This is taken up in the following paragraphs.

6 and 7. Area Computation and Production of Average Sand.—It is assumed that the area beneath the segment A B and above the line of economic limit, or A B C D, represents production for the average sand or well. For the determination of this area Simpson's Rule is used, although a planimeter or any other method of obtaining area is satisfactory.

By the rule. the base C D is divided into an equal number of parts, as (5) of Fig. 13. The ordinate corresponding to the division points are drawn and lengths then found. The formula is:

$$\frac{1(\text{A and N})+4\text{O}+2\text{E}}{3} \times \text{Distance} = \text{Area}$$

Distance being the spacing of the ordinates. The first (A) and last (N) ordinates are always multiplied by one, the other odd ordinates (O) by four and the even ones (E) by two. The sum is divided by three and the result multiplied by the distance between two consecutive ordinates. In the example only four equal parts are made and the formula is, therefore:

$$\frac{1\text{A} + 4\text{B} + 2\text{C} + 4\text{D} + 1\text{E}}{3} \times \text{Distance.}$$

The computation is

$$\frac{(5.00 \times 1) + (3.75 \times 4) + (2.71 \times 2) +}{3}$$

$$\frac{(1.77 \times 4) + (1.09 \times 1)}{3}$$

$$\times 1.36 = 15.227 \text{ sq. inches}$$

The average production per well was found to be 498,915 M cubic feet divided by 1.7, the average sands per well, gives 293,480 M cubic feet per sand. This amount represents the volume of gas in the area A B C D or to 15.227 square inches. The production per inch square is

$$\frac{293{,}480}{15{,}227} = 19{,}293.6 \text{ M cubic feet}$$

On the chart, time in years and each 100 pounds of closed pressure are one inch apart, making 100 pounds for one year equivalent to a square inch, or 19,273 M cubic feet. Had years been a half inch apart the same volume would be equivalent to 200 pounds, provided the length of the curve represented 24 years and not 12.

8. Line of Scale Computation.—Since one hundred pounds is too small to fix the scale, the amount has been multiplied by five. The corresponding production for five hundred pounds is 96,368 M cubic feet. On a scale or a sheet of paper with decimal divisions, a length equivalent to 96,368 M cubic feet, or 9.637 inches is taken and the zero end laid at the intersection of the 40 pound pressure line with the zero time ordinate and the other end opposite the 540 closed pressure point, that is, 500 pounds above economic limit. Each inch laid out on the line represents ten million cubic feet. Mark the points, and by horizontal lines construct the production scale along the left margin of the graph. Thus there is given a closed pressure, and a corresponding production scale.

Method of Use.—A sand with an average closed pressure of 700 pounds for the year is producing at the rate of 126,000 M cubic feet per year. It will produce 119,000 M cubic feet the following year and 82,000 M cubic feet the third year, etc. In the first case, the amount shown at 700 is the production for the year, and in the second, one horizontal inch below the intersection of the 700 line with the composite decline curve is the production, and so on for each successive year.

Where no closed pressure is given for a well the rate of production for any year will serve equally as well. It must be remembered that the production used in constructing the curve is on minute pressure above line estimates, and any results obtained are subject to correction to the equivalent of metered production. The same holds true where open flow tests are used to make this estimate. If meter readings are available, no correction is of course required.

Estimation of Future Yield by Closed Pressure-Minute Pressure Combination. —This combination has been devised as a simplification of the one just discussed. The difficulty in its use arises chiefly through lack of the detailed data necessary for its construction.

A closed pressure decline curve is first drawn using any of the various methods discussed. With a scale of pressures and one of effective minute pressures above line a scatter diagram is made of the various minute pressures given, against certain closed pressures. Through the thickest area or central tendency of points draw a curve which will be that of effective minute pressure for any given closed pressure.

For general use a refinement, namely time in line of wells for each year, is an essential addition. Production for the year, where using minute pressure, depends upon the time of operation of the wells. Hence when using this particular combination a postulation of probable periods to be operated must be made. In addition a history of previous time periods must be analyzed in conjunction with the decline curves in order to expand or decrease the future life of the well in accordance with the differences in the postulated past practices in operating over the probable future practices.

Advantages and Disadvantages of Method.—The curve is easy of construction, but as stated before, requires much detailed information. Like all closed pressure production combinations, the validity of its application to the area under examination should be tested.

Appraisal Of Oil And Gas Properties

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CHAPTER VII

ESTIMATION OF FUTURE YIELD PRODUCING WELLS: ULTIMATE AND FUTURE RECOVERY OIL OR GAS

FUTURE Estimated Production Curves and Tables.—Where total production for all future years is desired in place of annual amounts, a cumulative curve or table can be readily made up from the composite decline curve. The F. E. P. (Future Estimated Production) curve has the advantage of being easily read at any amount, thereby avoiding calculation for amounts not shown in the table. The F. E. P. curve should be plotted for a sufficient number of wells of various sizes to give an adequate basis for the curves.

Two methods of obtaining reserve totals can be used. (1) Arithmetical totals or (2) graphical totals. The arithmetic totals are more easily made up. Begin at the lower end of the composite curve and add each year's production consecutively to the total of those previously added. A number of these sums (F. E. P. of wells of various sizes) if plotted against the production of the year prior to the date of estimate, or production on the date of estimate, or on any other convenient reference, will furnish the basis for the curve. Thereafter, it is only necessary to have the production of a well for the reference period to obtain its total probable future. Fig. 16 shows an F. E. P. curve as worked out for gas wells.

The graphic determination of totals is only convenient when the decline curve indicates a short life and a rapid and early decline. On a strip of paper of suitable length lay off cumulatively along the edge successive ordinates for the middle of each year. At various places indicate what size of well would be required to produce the number of years in question. This strip is now used to lay out the proper length of abscissa for the several sizes of wells shown on the ordinate scale.

Still another method of drawing a future production curve is one given in the Manual for the Oil and Gas Industry, but this seems to have no advantage over the foregoing methods. The future production for a well of a given size is plotted vertically above or below the point on the composite decline curve representing the size of the well. Different scales may have to be used to get the two curves on the same sheet.

A table may be more practicable to obtain future reserves than the graph, especially where assistants are unaccustomed to reading curves, or if more than one person requires the data at the same time. The compilation of the table is simply to summate the annual

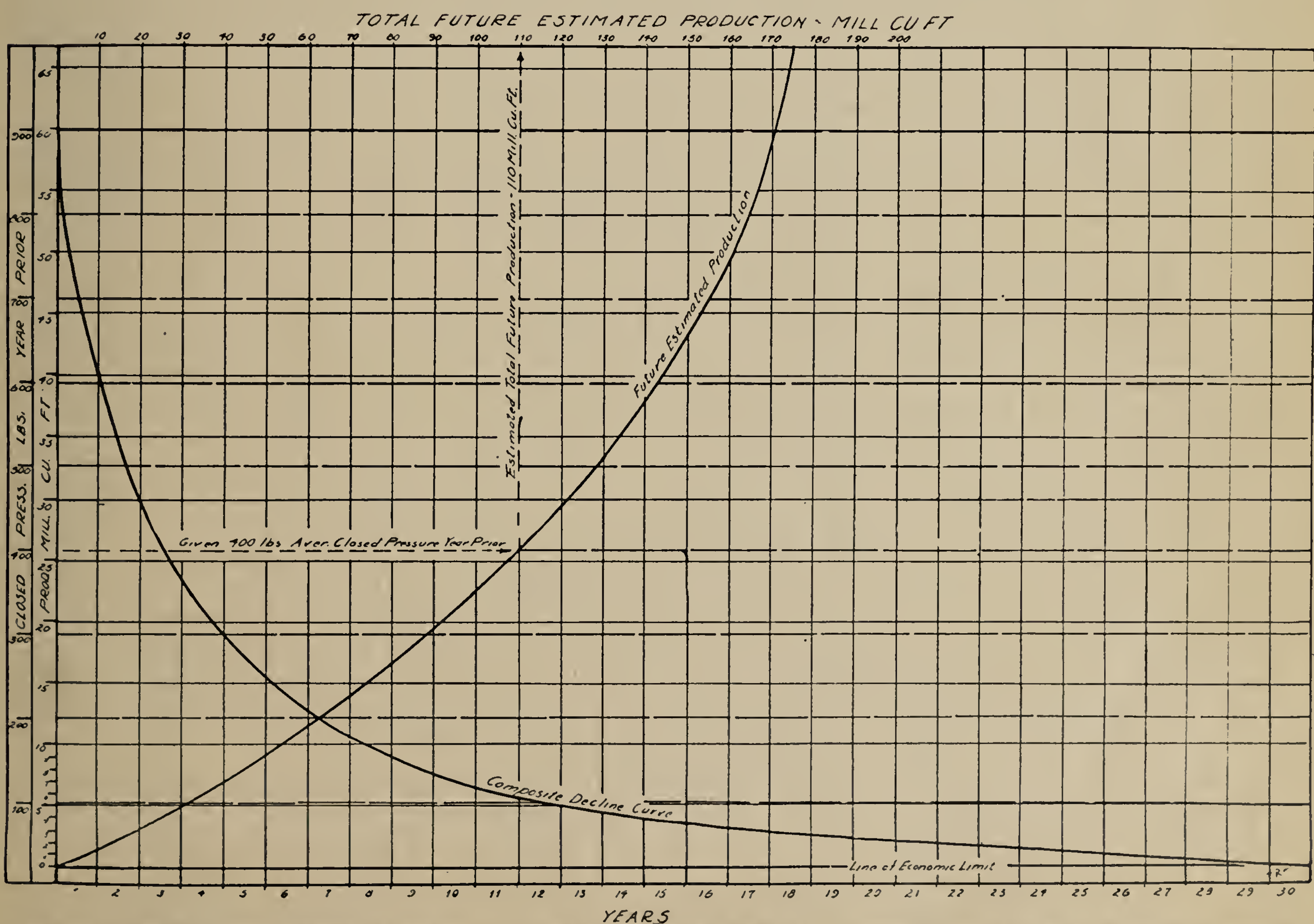

Fig. 16—Curve of future estimated production for an Appalachian gas pool. Composite decline curve on minute pressure estimates of production. Future estimated production curve corrected to 80% of value from C.D. curve.

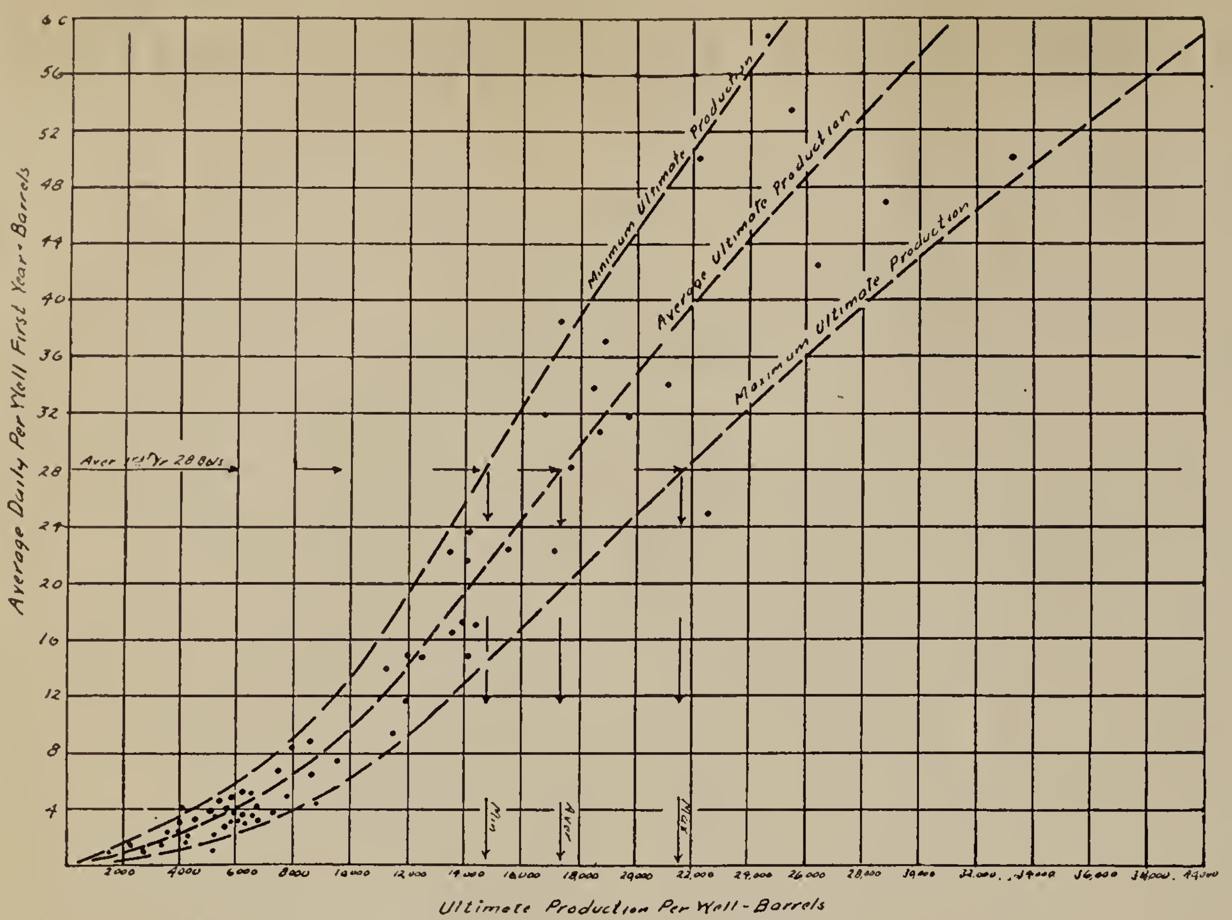

Fig. 17—Ultimate production curves. . Dots represent ultimate production per well of properties in the field for which drawn

future production of wells of various sizes in conjunction with a period of reference.

Cumulative Percentage Curves.—These curves have been described in detail in Chapter VI. It is only the case where an ultimate production curve is necessary to get a rate of decline curve.

Figure 17 shows both the cumulative percentage and ultimate production curves for the Robinson pool, Illinois. If the curves of future recoverable or ultimate future production are wanted, these curves are satisfactory where no greater refinement than is possible under the law of equal expectations is desired.

The cumulative percentage curve is interesting and useful for comparisons but it is seldom necessary to obtain an ultimate production curve. To avoid the complicated procedure described, decline curves on average wells of individual properties should first be drawn and extrapolated to the minimum economic limit. Summate the production of each year and plot the results in a scatter diagram as shown in Fig. 17, the scale being of average daily or average total for the first year, and the other scale that of ultimate production. More accuracy can be obtained if the points are weighted by symbols or numbers to represent the number of wells on the property represented by the dot. The points corresponding to the larger properties thus exert a greater influence on the direction of the curve than the points representing smaller properties.

Volumetric or Pore Space Method.—The method for obtaining reserves, as outlined in Chapter VI under this heading, gives directly an ultimate yield. The method is fundamentally impracticable for appraisal of the analytic type and has errors too high for any but the rarest use in undeveloped territory, and certainly none in areas having a known performance record.

If in spite of its known high error it is nevertheless thought best to use this method, not only must thickness of space and effective porosity be obtained, but some evidence must be sought on the point of greatest difficulty, namely the percentage of the entire reservoir content of oil which can be recovered.

Check of Results.—Every appraiser should reduce his ultimate production results to some common unit such as the acre-foot yield. As statistics on the various pools and productive sands accumulate, the reduction of production data to a common basis will prove very valuable. It will afford the opportunity to determine at a glance whether the estimates are correct. Furthermore, when a "wildcat" well is completed in a known sand, some idea as to the limits of ultimate yield and therefore the value of the well are quickly ascertainable. In the case of large appraisals where the detail herein described is irrelevant, such "yardsticks" as the acre-foot yield, barrel-day and others become indispensable.

Gas

Future Estimated Production.—The principles for finding the total future production of a gas well without showing the annual amounts are similar to those described under Oil and Gas. The diagram in Fig. 10 is added for illustrative purposes.

* * *

Chapter VIII

ESTIMATION OF FUTURE YIELD UNDEVELOPED AREAS: PROVEN AND UNPROVEN

Oil or Gas

Estimation of Underground Reserves on Undrilled Locations.—It is much more hazardous to attempt to estimate the probable production of wells not yet drilled than of those already producing. This hazard increases with the distance from production to a point where the risk is so great that the well is considered a "wildcat". When there is no performance record, relatively more attention must be given to any other data, such as the history of nearby developments and geological conditions.

The first question concerning a location is what chance does it have of being productive. The answer is found in the study of the structural and stratigraphic conditions, the nature of the sands and the relation of dry holes to the producing wells drilled in the lo-

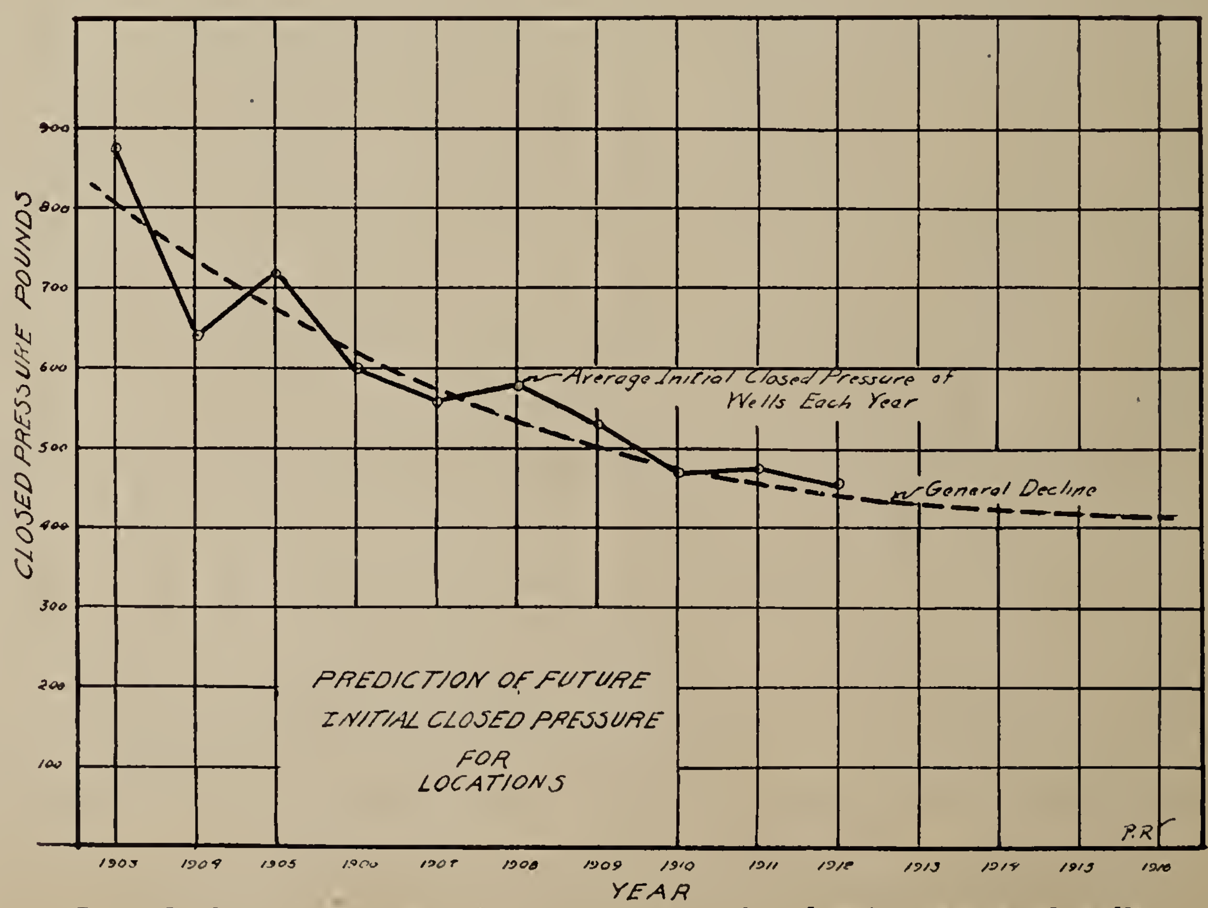

Fig. 18—Graphical method for predicting initial closed pressure of wells.

Fig. 19—Graphic method of calculating loss of oil where offsetting with a fewer number of wells. (After Johnson and Huntley)

Offsetting	200 feet from line	150 feet from line
Along the long side of an eighty		
Case 1—5 wells meeting 8 on the side of 8 tens lose	1.05	1.69
Case 2—5 wells meeting 6 on the side of 2 forties lose ...	0.55	0.80
Case 3—4 wells meeting 5 on the side of an eighty lose ..	1.01	1.88
Along the side of a forty		
Case 4—3 wells meeting 4 on the side of a forty lose	0.24	0.42
Case 5—3 wells meeting 4 on the side of 2 tens lose	0.13	0.41
Case 6—2 wells meeting 3 on the side of a forty lose	1.39	2.49

cality under similar conditions. The last is discussed in more detail under "Discount and Investment Risk".

The next question concerns the size of the well. If the location is in the proximity of producing wells, the problem resolves itself into two parts:—

1. A calculation of the loss in pressure after the other wells are drilled.

2. Evidence as to whether the dip may cause some of the reservoir thickness to contain gas or water instead of oil, or whether the pay is decreasing in thickness and porosity in various directions. For the items just mentioned all the resources of the petroleum geologist are needed. As to pressure, or initial production, it is possible to construct a scatter diagram of all initial closed pressures or productions of wells by years, and draw on this a smooth average curve. In a pool which has been operating for some years the results obtained are reasonably accurate. Accuracy in this case depends upon the number of cases, for in all gas estimates individual instances are not a fair measure, but the average of a group of wells is required.

This same method of the scatter diagram should be employed to ascertain the amount of allowance to be made for any other variable, such as change in the thickness of the pay.

Unless the intention is to drill in the near future the estimates will be too high and if delay is long, the location may be so depleted as not to warrant drilling. Delay means possible completion of the other wells within the drainage area and consequent withdrawal of part of the oil or gas contents. This withdrawal reduces the pressure needed for the expulsion to a stage prohibiting drilling for the small amount still recoverable.

The closer a location is to other wells the more important it is to complete the well at an early date. This interference from outside wells cannot be definitely measured, except in unusual cases where the drilling program has been carried out in such a manner as to make possible the computation of the same.

Initial Production Curves.—Suppose a field has been in existence long enough to yield data sufficient for the construction of a curve of the decline in initial flow of oil, or of the pressure of the gas. For either case the procedure is the same. The average initial quantity in the case of all wells completed each year, when plotted on quadrillé paper, generally shows the tendency of the pool. By use of analogous wells having a long history, or the extrapolation of such curves, if not long enough, the initial yield or pressure for wells yet to be drilled is determined.

Having drawn such a curve and predicted the initial production or pressure, it is then necessary to estimate ultimate production from the decline curve of the pool. Two factors of risks are likely to enter, that of getting a non-producing well, and the other of getting a well which is not likely to produce as well as the average well in the field. This latter risk can be ignored if the composite decline curve was based on practically all the wells in the pool, for in such cases the risk is automatically provided for by the effect of the inferior wells included in the curve. A gas company may suddenly decide to operate all the gas wells in a field to nearly full capacity rather than in accordance with the previous average of seven months a year. This would tend to increase the rate of initial pressure decline over that postulated. Furthermore, in case the efficiency of an organization decreases through change of management, some mistaken policy may result in reducing the reserves or increasing the unit cost. The failure to keep up necessary repairs and maintenance, with consequent admission of water to the producing horizon, or abnormal leakage of the gas to non-producing sands may greatly damage or terminate a promising pool. Encroaching water in the producing sand may become more serious than at first estimated and may thereby increase the abandonment pressure and so lessen the reserve.

If it is planned to space the undrilled wells closer than the drilled wells which are being used as a basis of estimate, due allowance must be made, as the recovery production is naturally not so great for each well in the case of closer spacing. However, the ultimate yield per acre for the tract is increased. It is, therefore, desirable that all composite curves should be accompanied with the data as to the spacing of the wells used. It is unfortunate that these important data are lacking in so many of the curves published by the Treasury Department.

Acreage Classification.—The reserves on each property vary of course from part to part. A tract must be split up into parts to be differently valued. The names given to the categories are less important than the percentage chance assigned to each. The classes may be few, or it may seem desirable to recognize many. The Government in Form O Questionnaire[1] outlines five classes of acreage as follows:

1. Producing.
2. Proven.
3. Probable.
4. Possible.
5. Worthless.

It is well to follow this nomenclature, at least in tax work. The hazard of getting a producing well, as is obvious, increases with each class until in the fifth the risk is so great as to make the acreage valueless.

The term "proven acreage" is ordinarily interpreted somewhat freely. It need not mean 100% proven, but rather that there is a chance of more nearly 95% being productive. Where this is the case, the land should of course receive its 5% reduction. Between this and "worthless acreage" it is convenient to recognize the other grades, but since the terms "probable and possible acreage" are also vague they should be supplemented by the percentage of risk. Instead of these two there may be three or more subdivisions characterized by the percentage of chance represented.

The class of worthless acreage includes that which has been worthless since it was obtained or since the last rental was paid; or it may be that which the company on inadequate grounds considers of little value so that its rental has been discontinued. Land should not be classed as worthless, if it can be sold even though the appraiser himself may think it will be dry or will never be drilled. On the other hand, when, owing to the drilling of a recent nearby dry hole, it is evident that the land is not considered worth its rental the acreage probably is worthless unless there is very good evidence to the contrary.

Determining the Number of New Wells Needed to Maintain Output.—In appraisal it is frequently advisable that the rate of recovery be studied with a view of planning the drilling program. This is important for a large company with groups of holdings sufficiently large to warrant such a procedure. Or the problem may be to obtain the number of wells requisite for the maintenance of the production of a state or nation.

For a large area, a simple process is to plot the average annual production per well and find the rate of decline in percent.[2] This would be the normal decline. In fields where new wells are constantly coming in and where no falling off has been noticed in the gross

1—Form L, N and O Questionnaires to be filed by taxpayers claiming depletion. Forms L and N were published in 1918 and O in 1919. They are issued by the Oil and Gas Valuation Section, Bureau of Internal Revenue.

2—Beal, C. H., Decline and Ultimate production of Oil Wells, with Notes on the Valuation of Oil Properties: Bureau of Mines, Bull. 177, 1919. p. 70.

pool production, the normal decline method to be described is unnecessary.

Assume the following:

Pool with 2000 wells, June 1, 1922. Production per well declining at the rate of 10% per year of previous year. Average well production as of June 1, 1922, 50 barrels. Daily production of field June 1, 1922, about 100,000 barrels.

Problem:—To find the number of wells necessary to produce 100,000 barels per day on June 1, 1923.

With the above information it is evident that the daily rate a year hence will be about 45 barrels. To produce the desired amount at this rate, it will take about 2222 wells (100,000 ÷ 45) or 222 more than the year prior, (2222 — 2000).

Or if it is desired to increase the daily production, add the amount of increase to the 100,000 and proceed as before. Dividing the new amount by 45 gives for the quotient the total number of wells necessary, and the difference gives the number of wells to be drilled.

The methods described are general and make no provision for the effect of the disproportionate amount of production being made up from the first year's production of new wells on the totals, where an increase in the current rate by drilling is planned.

On individual or groups of individual tracts, a curve of the decline of the initial production of successive wells will enable one to predict the size of wells at various times in the future from the wells already drilled in the old pools, and thus a closer estimate of the number of wells to be drilled can be made. There should also be an allowance made for drilling the normal percentage of dry holes that would be drilled, a factor omitted in the example given above. Elements such as sand, thickness, structure, etc., are to be taken into account, which may indicate that the new wells will not be as good as a study of the wells already drilled would indicate.

Spacing of Undrilled Wells.—The appraiser should consult the company geologist, the executive responsible for the location of wells, as to the spacing policy. The policy of the organization in this respect can sometimes be inferred from the spacing of wells already drilled. This assumption would prevail in the valuation of many holdings where the time needed to ascertain closely the future spacing program for each lease would not be warranted.

However, the spacing of wells is of fundamental importance and one to be carefully considered in refined appraisal. In spacing wells, the desire of course is to obtain the maximum recovery from the minimum number of wells, as this would yield the greatest profit. A number of factors to be considered by the operator in fixing the spacing are:—

(a) Porosity and fineness of sand.

(b) Viscosity of the oil.

(c) Dip of formations, more important in coarse, porous sand.

(d) Property lines and offsetting wells; whether drilling agreements can be made with neighbors or whether close offsetting and aggressive operations must be resorted to. Also the shape of the tract; whether compact or with a long boundary line relative to the area.

(e) Amount of pressure of the gas in the oil sand or the prevailing pressure of a nearby gas well.

(f) Water conditions in the oil or gas sand.

(g) Cost of the well and maintenance in proportion to its yield.

(h) Commitments contained in leases under which the property is operated.

(i) Other financial considerations, such as, how many wells must be drilled annually to keep up production, and also what the policy of the company is in regard to the rate of speed in draining a property.

The table and drawing of offset well losses shown on page 84 gives the territory lost if offsets are made as indicated.

Offsetting

The method of ascertaining the lost area is to draw lines on the map midway between each line well and each of its two opposing line wells, if one is not exactly opposite. This is done by drawing circles with each well in question as a center and joining the points of intersection with a line. These lines make triangles with the lease boundary showing areas lost or gained. The area can be calculated by multiplying the base by half the altitude of each triangle.

In estimating the recoverable reserves on undeveloped acreage, one method is to reduce the ultimate yield on developed acreage to a barrel per acre basis.

A shorter and useful method is to use the value per acre for the area of one of the producing wells and to express the undeveloped acres as having a fractional value of the producing average, the factor to be used being determined by the percentage chance of success modified by such considerations that would indicate that the undrilled acreage would be less valuable even if successful.

For irregularly shaped leases, it is well to plan several methods of placing wells. To advise drilling an extra well, tables can be devised showing the gain in production per acre by the procedure. However, the cost of wells, price of oil, royalties, operating expenses and other items must be considered in conjunction with the increased recovery.

Appraisal Of Oil And Gas Properties

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CHAPTER IX

ESTIMATION OF FUTURE YIELD —REFINEMENTS

Oil or Gas

Methods of Making Closer Reserve Estimates.—[1]In using composite decline curves for estimations, size has been the only consideration, except for age, in the age-size method. This is not consistent with the accuracy essential to commercial appraisals. Moreover, the shape of the production decline curve is determined by the combined influence of a number of factors, and the influence of any one of these varies with the local conditions of each group of leases or of each pool.

Some of the other factors that may be studied when greater refinement in appraisal is desired are; the effect of (a) acreage per well, (b) the depth of producing sand, (c) the thickness of producing sand, (d) the gas pressure, (e) the texture of the oil sand, (f) the quality of the oil, and (g) location on geological structure.

Acreage Per Well.—Beal made a study of ultimate production to acreage per well in the Crawford County field, Illinois. It was found that the greater the acreage drained, the greater is the ultimate yield. This fact hardly needs proof as nearly every operator is aware that within limits large acreage per well means longer life and greater production.

Thickness of Oil or Gas Sand.—It is much more difficult to obtain information on the exact thickness of producing sands and consequently the effect thereof can seldom be considered. Though figures are usually available they are for the most part unreliably determined. Particular care must be taken to differentiate "pay" sand from non-productive portions of the sand so far as feasible.

Depth of Oil Sand.—A study of this factor would aid in qualifying wells when using composite curves. As a rule, the ultimate production is greater with greater depth of wells, other things being equal.

Gas Pressure.—Lewis[2] places special stress on the possibility of using rate of decline in gas pressures to estimate reserves. He suggests that by observing the quantity of gas produced with oil during part of a well's life, and the decrease in gas pressure and the variation in the composition of the gas in the time mentioned, it may be possible to determine, by the laws of the physical relations of gases and liquids, whether all or what proportion of the gas has been held in solution, and further to calculate the quantity of oil underground in which the gas has been absorbed. This would be well worth while where the casinghead gasoline is being extracted and a considerable part of the valuation attaches to the gasoline content. Otherwise, instead of acting to vary the reserve estimates the pressure will serve more as a check on the estimates made at least for the present. The regular recording of pressure in oil wells is a very desirable innovation.

Texture of Sand.—No data are available as to the effect of sand characteristic or yield other than those in the laboratory. These experiments showed that the texture of sand, if determinable, is an essential consideration, Here are some general figures:—

Estimated Average Capacities of Oil Sands[3]

	Estimated average porosity %	Capacity per acre foot lbs.
Appalachian field	12½	970
Illinois and Mid-Continent fields	17½	1,353
California fields	25	1,940

Viscosity of Oil.—The viscosity of the oil is not likely to be a factor necessitating modification of the data for the decline curve where production is all from one sand. However, this is not always the case, especially in the Appalachian and Mid-Continent fields, where frequently three or four sands are productive on the same property. The Cushing field in Oklahoma is an excellent example.

Coarseness of Sand.—Experiments conducted by Lewis[4] reveal the great importance of the size of the sand grains and hence of the pores between the grains. Tubes were taken and each packed with either coarse or fine sand. The coarse grains had an average diameter of about 6/254 of an inch, and a porosity of 37%, while the finer and more angular grains averaged about 3/254 of an inch in diameter and had an average porosity of 38.5%. The sand in the tubes was saturated with oil forced up from the bottom and was then allowed to drain until there was no noticeable change in weight.

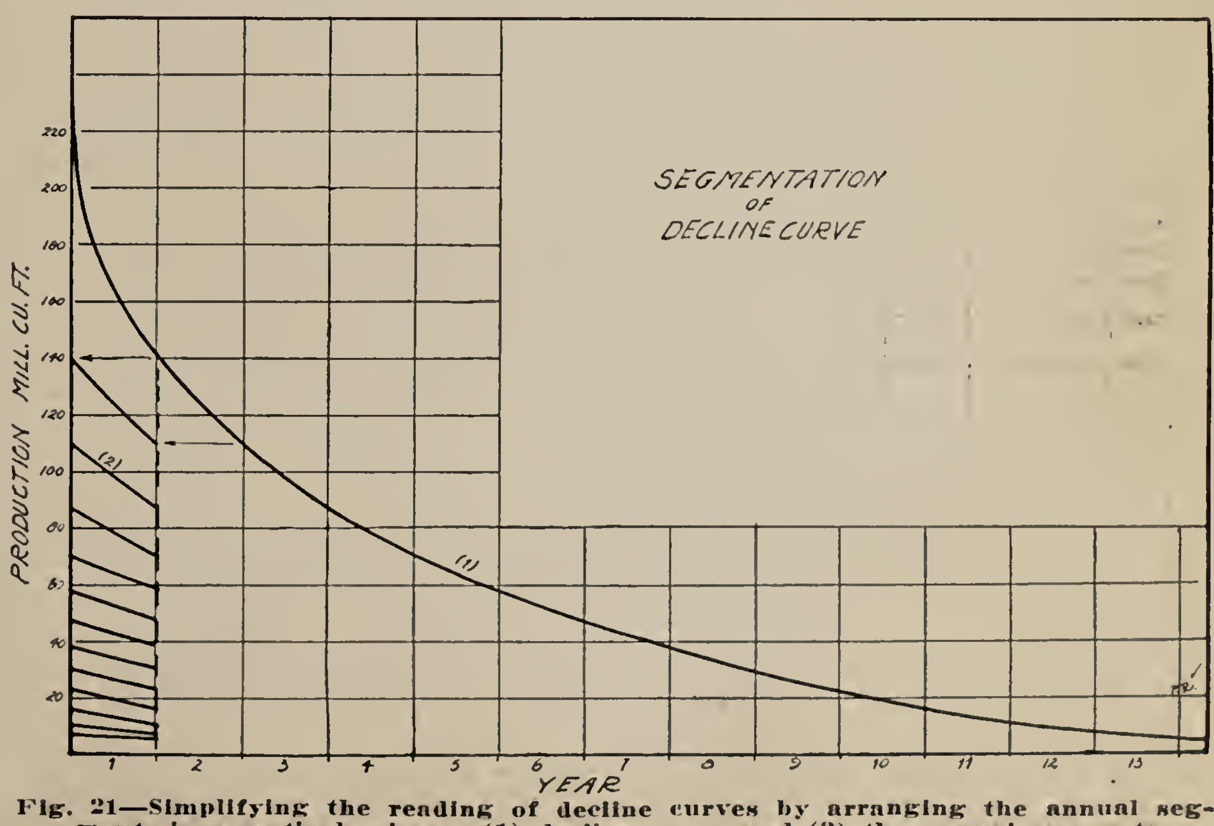

Fig. 21—Simplifying the reading of decline curves by arranging the annual segments in a vertical column; (1) decline curve, and (2) the annual segments

1—Beal, C. H., The Decline and Ultimate Production of Oil Wells, with Notes on the Valuation of Oil Properties: Bureau of Mines, Bull. 177, 1919, pp 42-49.

2—Lewis, J. O., Methods for Increasing the Recovery from Oil Sands: Bureau of Mines, Bull. 148, 1917, p. 27.

3—Lewis, J. O., Methods for Increasing the Recovery from Oil Sands: Bureau of Mines, Bull. 148, 1917, p. 28.

4—Lewis, J. O., Methods for Increasing the Recovery from Oil Sands: Bureau of Mines, Bull. 148, 1917, p. 23.

The following table gives the results of the experiments:

Quantities of Oil Retained in Drained Sand

Oil	Sand	Time drained Days	Oil retained Percentage of capacity of sand
Bradford crude. Gravity 41.2° B. (0.818)	Coarse	26	15.0
" " " " " "	Fine	26	21.0
California crude. Gravity 25.1° B. (0.903)	Coarse	42	24.0
" " " " " "	Fine	43	42.0
California crude. Gravity 14° B. (0.972)	Coarse	73	30.5
" " " " " "	Fine	73	53.0

Location on Geologic Structure.—Although definite figures are not available, it has been observed, in some pools, that properties most favorably located on a structure have the longest life and consequently yield a greater ultimate amount.

Hydrostatic pressure is a more important force to consider than gravity. The movement of oil down the dip by gravity is very slow and practically nil with the degree of the dip and the degree of fineness of the sand prevailing on most Mid-continent and Appalachian structures.

Salt Creek, Cushing, Haynesville and many other pools have a definite water line. Under such conditions the encroachment should be considered and the appraisal of each property should be modified accordingly.

Limiting the Estimates by Correction Factors.—By quantifying the various factors discussed, it is often possible to reduce the margin of error in estimating reserves to within reasonable limits.

From data on depth of well, sand thickness, and acreage per well it is possible to revise the ultimate production estimates in accordance with the factors mentioned. For example, assume that a well (a) produced 36 barrels a day the first year; (b) is draining an acreage of 8 acres; (c) has a depth of 1000 feet to the sand; and (d) has a sand 24 feet thick. The maximum and minimum ultimate production are determined under each condition. The following table shows the results obtained:

Limits of Ultimate Production Established by Each Factor.—Barrels

	Production first year	Area drained	Thickness of sand	Depth of sand
	36 barrels	6½ acres	24 feet	1,000 feet
Minimum	17,200	16,900	10,000	9,600
Maximum	26,200	23,000	32,000	26,600

The limits are 17,200 barrels as minimum and 23,000 barrels as maximum. Thus instead of 17,200 minimum and 26,000 as maximum, the limits are reduced to a range of 5800 barrels instead of 9000 barrels.

Extrapolation on Logarithmic Paper.—The decline curves usually obtained do not extend to the economic limit because records of such old wells are frequently not available. and partly because reserve estimates are more often desired in comparatively new fields. However, it is not difficult to extrapolate the extension of the curves on logarithmic paper. A study of many of the more symmetrical curves will reveal a similarity to a hyperbola of the type formula $yx^n = K$. Hyperbolic curves, if plotted on logarithmic paper, become a straight line. Logarithmic paper, instead of having uniform spacing in both vertical and horizontal directions, as in the case of quadrille paper, is drawn to a logarithmic scale. Thus when plotting on this type of paper, the change in scale should be noted. In only one position on the paper will the points arrange in a straight line. If they are not in the correct position the direction of convexity of the points plotted indicates the direction in which they should be moved to make a straight line. By trial, shift each of the points the same number of units until the correction position is found. It may require several shifts before one gets a straight line. Once having a straight line, it is a simple matter to extend it downward to find the future production. If the whole line cannot be straightened, straighten the few later years.

Figure 20 illustrates the shifting of points on logarithmic paper until they fall in a straight line.

Only in cases where it is impossible to extrapolate on logarithmic or semi-logarithmic paper is a guessed curved line extension on quadrillè paper permissible. It is nearly always better to assume a hyperbolic curve than to guess wildly at a projection on quadrillè paper.

Curve Segmentation.—This is nothing more than a decline curve segmented and arranged in such a manner as to facilitate reading of future annual reserves. The segments representing each year's decline are arranged in a

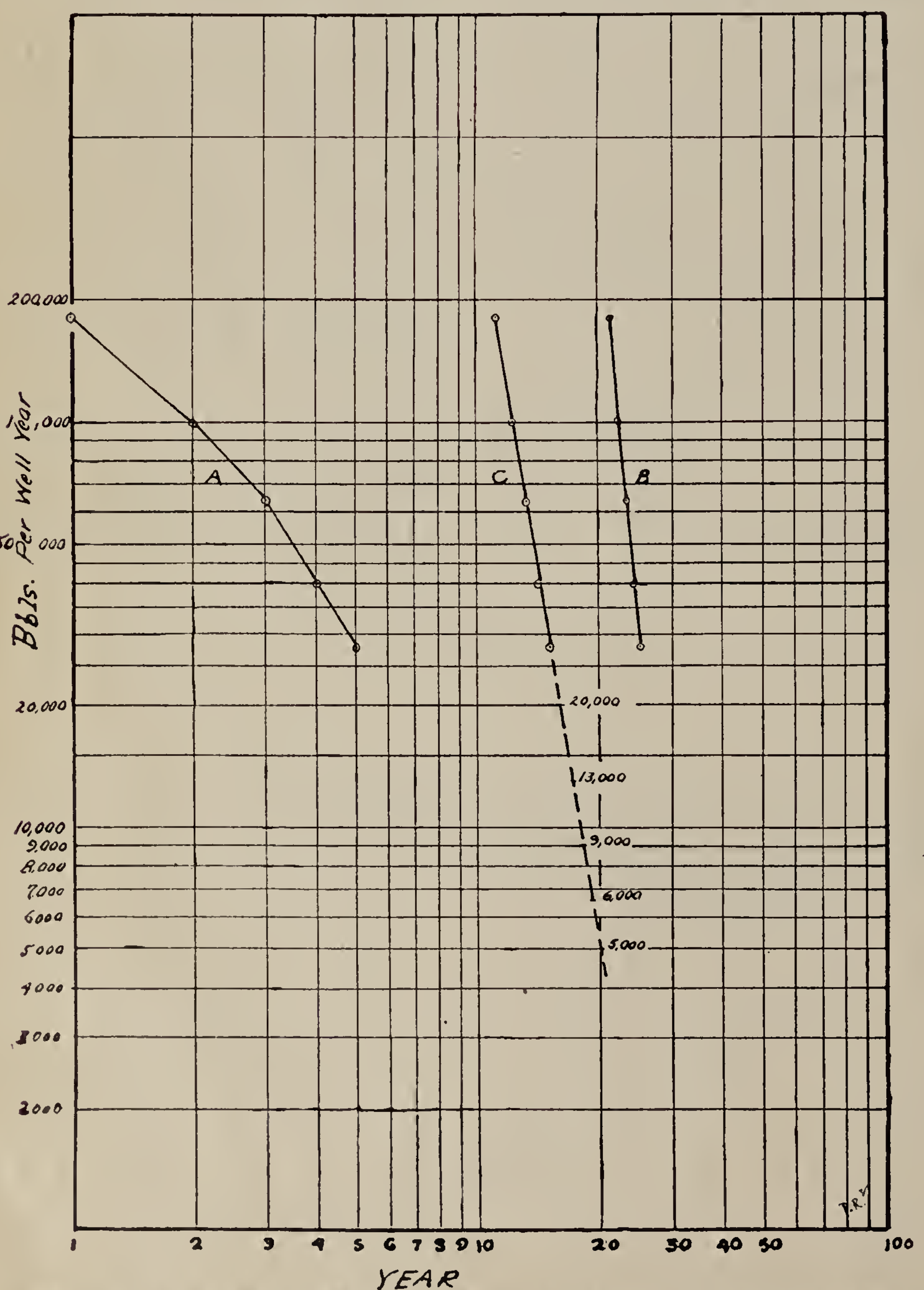

Fig. 20—The straightening of curves on the logarithmic paper, (a) is the original plotting; (b) the second plotting but moved too far to the right and line has become concave and (c) the final plotting in which the points are all in a straight line and in position to be extrapolated

vertical column. Three points and often only two suffice to fix each segment. The diagram, figure 21, is a demonstration curve. The segments are found along the left, convenient to the scale. Having found the starting point on any segment the production for each year in the future can be read from the successive segments in order, the amounts being vertically below the starting point.

Well Year Equivalent for Well Operated Part of Year.—The production of oil on one lease is run into one tank as a rule except in California where the daily gauge of oil from each well is common practice. This necessitates calculation of a well year equivalent for all new wells which did not produce the whole year, or wells which were abandoned during the year.

In the matter of gas production, one well is often regarded by the appraiser as being representative of several or all. Tests are taken at intervals (at this well) and the others are assumed to be relatively the same. In any given group there are always new wells drilled, old wells abandoned, or those operated are turned into the line only part of the year. For this reason some means for finding well-year equivalents is necessary. Tables are used by some workers and diagrams by others.

A well operated intermittently must be reduced to the total time it was in use and its production read from the chart or table. For convenience, in addition to months and days, consecutive numbering of days of the year, if placed on the chart and tables will save using calendar dates and instead, for wells operated intermittently, the period run can be taken readily as from the beginning of the year and interpreted to well year equivalent. The tables will be found in the appendix.

Oil

Average Age of a Barrel of Production.—When estimating future production on the basis of average production per well for a tract on which the wells are of different ages, some adjustment factor becomes essential. This is not necessary when one uses the Time Decline Period curve, and this constitutes one of the advantages of this type of curve. However, with the Percentage Decline curve, where all references are in relation to the production of the first year, the position of the production data in the curve must be found.

To facilitate this, Washburne[5] suggested a method for determining the average age of a barrel of production and Beal[6] added to the discussion.

The method consists of weighting the well productions by its fraction of a year's age during the early life of a lease or a group of leases. This weighted average age when found determines the time from the begining df the decline curve represented by the production of the wells.

Gas

Individual Sand Composite Decline Curves.—The most imprtant refinement in gas appraisal is that of segregating all data with reference to the respective producing sands. The composite decline curve instead of being for a field can be divided and a separate one can be made for each sand in the pool. It must be borne in mind that one pool cannot be in two sands although one may have one pool overlap or overlay another.

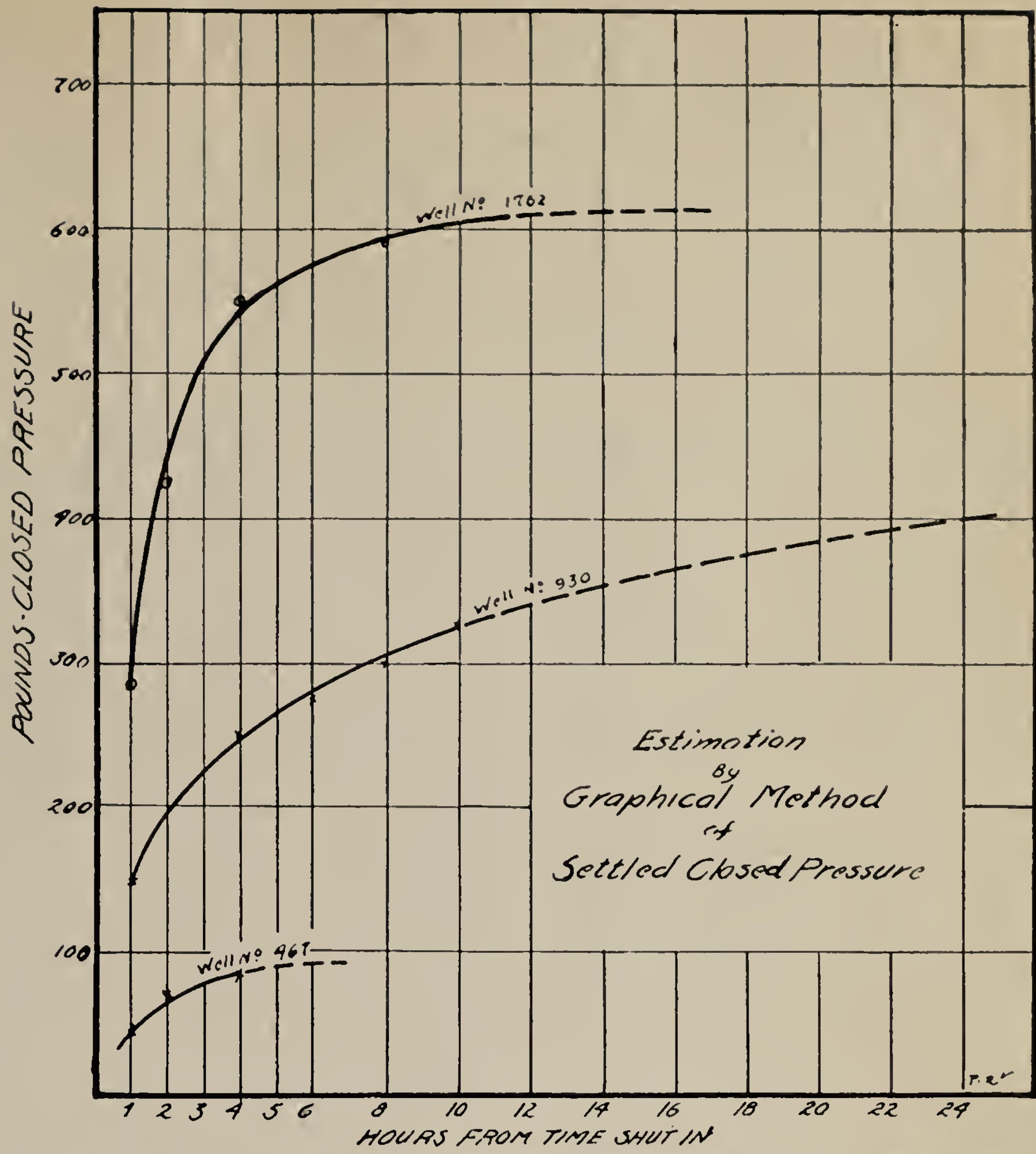

Fig. 22—Calculated settled close pressure where a well cannot be closed in the required length of time. Well number 467 has built up its pressure in six hours, while wells number 930 and 1762 require 24 and 14 hours respectively

Compressibility of Natural Gas at High Pressures[7].—It has been found that, due to the high compressibility of natural gas, a considerable error is introduced when natural gas is measured at high pressures. The assumption that volume is proportionate to pressure, as held by those applying Boyle's law to the computation of gas volume, necessitates the use of correction factors, if the true amount is desired. It has been shown that a correction percentage of over fifteen percent is required for pressures above five hundred pounds. From the information given in the Technical Paper referred to, a chart has been constructed showing the correction factors.

Graphic Device for Calculating Closed Pressure.—Very often the amount of production from a well is needed, yet to shut the well in even for a day would mean a hardship to certain consumers. Where a fairly reliable test is desired, in such cases, the well can be closed in for a few hours instead and readings may be taken at various intervals. When these are plotted and a line is drawn through the points and extrapolated, the appraiser will have an approximate estimate of the reading at the time when pressure has very nearly reached its maximum. A chart illustrating the method of plotting is shown in figure 22. The pressure readings as taken are charted against the span of time from the closing of the well.

Correction of First Minute Reading.—As a rule the first minute reading is more inaccurate than any of those taken later. This is the result of the impossible demands upon the tester, who is required to shut the gate which requires some time and make a reading in one minute. It is not possible to close the gate with the same speed and consequently the reading is incorrect. For this reason where more accurate first minute readings are desired, a graph of the later readings extrapolated to the first minute yields the desired results.

5—Washburne, C. W., The Estimation of Petroleum Reserves: Am. Inst. Min. Eng., Bull. 130, Oct., 1917, pp. 1866-1868. Discussion of paper by Pack, R. W., Am. Inst. Min. Eng., Bull. 128, Aug. 1917, pp. 1121-1134.

6—Beal, C. H., The Decline and Ultimate Production of Oil Wells, with Notes on the Valuation of Oil Properties: Bureau of Mines, Bull. 177, 1919, pp. 62-63.

7—Burrell, G. A., and Robertson, I. W., Compressbility of Natural Gas at High Pressures, Bureau of Mines, Technical Paper 131.

Appraisal Of Oil And Gas Properties

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Chapter X

PREDICTION OF FUTURE PRICES

Oil

THE prediction of future prices is the most difficult and next to the estimation of reserves is the most important operation in appraisal. When a company is seriously considering abandoning an oil property the factor of the future price is quite as important as the calculation of the ultimate production.

There are those who, finding that predictions made in the past were erroneous, decry all attempts to postulate the future price of oil. But when we recognize that all such estimates, though always subject to more or less error are yet nearly always closer to the truth than the hypothesis of no change, the wisdom of making the best predictions possible becomes clear.

Of course, once an estimate of future prices has been made, the appraiser should not hesitate to revise them with the accumulation of new facts.

Classes of Information Required.—The postulation of future prices necessitates the application of a combination of statistical, geological, engineering and business principles. That many oil men rely on business acumen alone is reflected in the bankruptcies or losing sales. Those purchasing production in the winter of 1920 and the spring of 1921 on a barrel-day price commensurate with the posted price did so because, with the sun shining, the clouds on the horizon were overlooked. No matter how complete the information in hand, one should never neglect to bear in mind the probable error involved. Frequently possible maximum and minimum limits may be added but some one course of prices should be stated as the most probable.

Those who have attempted predictions find it is not a problem solved by one alone. The man trained as an engineer may be qualified to assemble the data and draw certain conclusions, but he needs to gain valuable information by consultation with those in other technical branches and in the executive staff.

Relation Between Future Price and Drilling Program.—Among other reasons for desiring estimates of the future price of oil is the knowledge whether immediate or delayed development of an area would finally yield the greater return. Often the situation is such that probable prices have no influence on the program of the operator, particularly where competition is forcing immediate development, or lease contracts stipulate wells to be drilled within a certain time. Where a field is under competitive development so that the oil must be gotten quickly, much depends upon the price months hence, whereas under the opposite condition of monopoly, more depends upon the price several years hence. Furthermore, price generally has a greater influence in areas of small production than in those of large production as a drop of a few cents per barrel may mean inability of the company to operate further at a profit. During the period of high prices in 1920, this was demonstrated by the opening of wells which had been abandoned years ago because of their small size. Of course, the greater the initial investment, the more necessary is the assurance of a stable or rising market.

Factors Affecting Future Price[1]—The factors affecting the future price of oil may be divided into two groups, the historical and the non-historical[2]. By historical is meant those influences that have existed to date and indicate their importance as price barometers for the future by their actions in the past. By the non-historical is meant those elements that are only now beginning to be evident, and especially those that have yet to show an effect, but the influence of which is predictable.

A division into the two groups will be attempted, although the interrelation is often so apparent that classification is optional. Since the principal step is a study of historical influences, they will be listed first:

Price Influences

1. Posted prices to date in the field under examination, and also posted prices in other influencing fields. These are more usable when plotted on a chart in conjunction with other information shown by similar curves.

2. Annual production, by fields, of the United States, of countries competing in our markets, and in the world market.

3. Annual exports and imports.

4. Reserve stocks on hand each year.

5. Annual refinery gasoline produced.

6. Annual natural gas and casing-head gasoline produced.

7. Price of gasoline each year.

8. Amount and price of other major refined products. (This is not always essential, although under the 1921 conditions, the gasoline price was kept up by the lack of a market for the other products, the operating costs being paid by the gasoline sales alone.)

9. The number of pleasure cars registered each year, with a study of the probable point of saturation of this type of car.

10. The number of tractors in use each year.

(From 9 and 10 it can be observed how the production per vehicle has been changing.)

11. Population of the United States for each census. To be used with figures on per capita consumption.

12. Annual price and production of other important commodities, such as corn and wheat; to be used mostly for the purpose of comparing price conditions.

13. List of Bradstreet's, Dunn's, the Bureau of Labor's commodity and other index factors. The relation of each change in price to the average price of all other commodities can be noted and the beginning of the influence of certain factors on the price of oil can be determined.

14. List of the indices of the Federal Reserve Bank deposits.

15. Exhaustive study of some other natural resource which has passed through a condition or series of conditions that are anticipated for the oil industry.

16. Opinions of leading economists on the financial conditions.

After a comprehensive study of the historical factors that caused price changes in the past, an appraiser can postulate future price. These results, however, must then be increased or decreased by the more indefinite, non-historical influences, as:

1. Possible maintenance or increase of the country's production by new fields.

2. Probable future of oil fields in competing countries.

3. Political influences at home and in other countries.

4. Knowledge of progress in the retorting of oil from shale.

5. Introduction of shaft and tunneling for oil mining.

6. Possible changes in the type and power of gasoline engines.

8. Possible adaptation of other than gasoline-burning motors.

1—For an excellent graphic presentation of many of these factors see Pogue, Joseph E. Economics of Petroleum: John Wiley & Sons, Inc., 1921.

2—Ruedemann, Paul, chapter ?? Business of Oil Production; Johnson, R. H. Huntley, L. G. and Somers, R. E., John Wiley & Sons, 1922.

9. Increase of efficiency in refining processes that might produce larger amounts of gasoline, and the other most desired products, per barrel of crude oil.

10. The quality of oil in undeveloped pools and the average grade of all produced at present.

11. Public sentiment toward conservation and possible prohibition of fuel oil as a coal substitute.

12. Change in the demand for automobiles to one of replacements principally, rather than from new owners.[3]

Bearing of Factors on Price Movement.—The posted prices to date are of course the principal data for the investigation. For each fluctuation, the contributing causes should be found. Those causes which are likely to reappear should be listed for special attention, while those least likely tho influence price again can be eliminated. Of the latter the depressions caused by over-production in the Glenn and Cushing pools are striking examples. The present demand and present storage facilities have so altered the situation that one such pool alone could not exert so vast an effect.

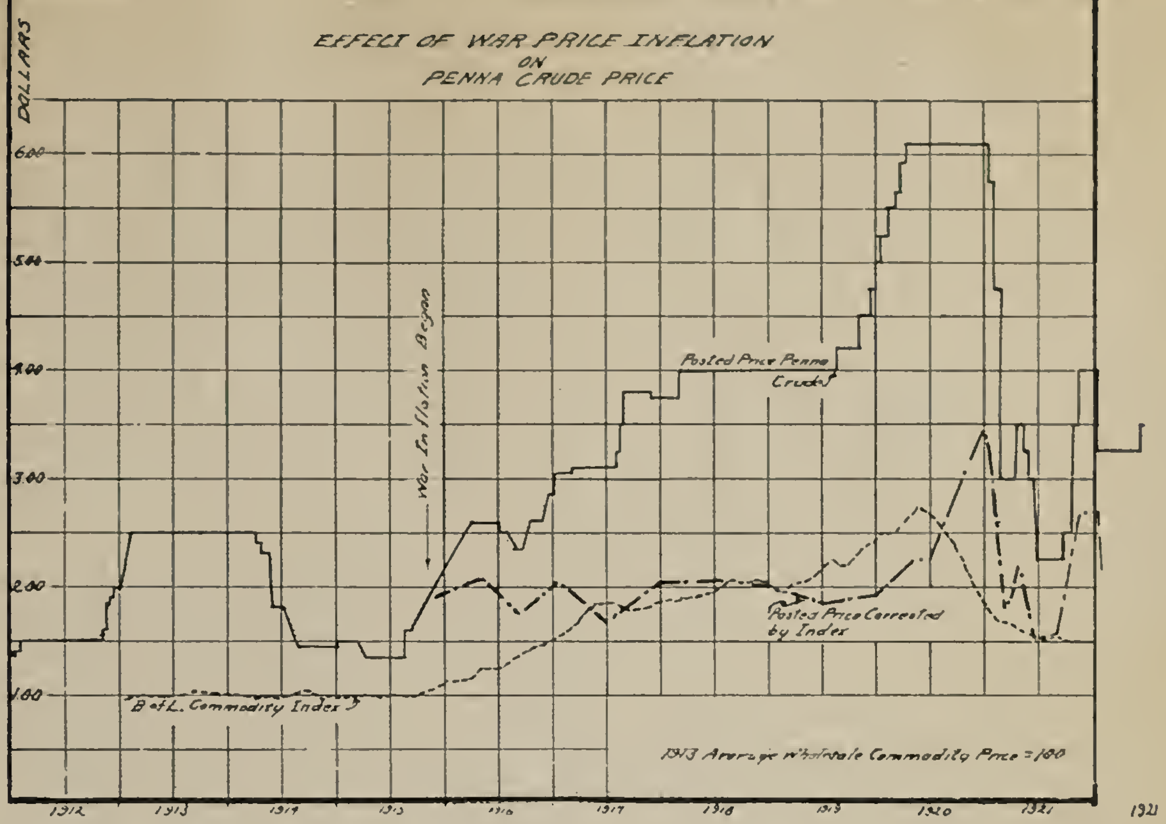


Fig. 24.—Diagram showing the posted price of Pennsylvania crude after inflation as found by the Bureau of Labor indices for wholesale commodity prices is deducted. (After Ruedemann, Business of Oil Production)

The consideration of the annual production by fields for the United States and by countries for those competing in our markets serves various purposes. When compared with prices for the same period, it brings out the tendency for changes in price to lag after changes in production. The course of producing fields, having a bearing on the market, should be followed.

Data on gasoline produced each year, the amount of gasoline per barrel of crude oil, and further, the number of gallons of gasoline and barrels of crude per motor vehicle are essential. The country's production in 1920 amounted to less than forty barrels per motor vehicle. The increase in the number of consumers of gasoline has been greater than the increase in production and consequently a gradual decrease in the amount available to each consumer is to be noted. There is a limit to the amount of gasoline that can be distilled from a barrel of oil. But we can expect an increase in the use and efficiency of "cracking" methods, a decrease in motor requirements by the use of lower grades of fuel and of gasoline substitutes, and a change in power and types of motors. The average town car has much more power than is ever needed. At present there is an unnecessary consumption of gasoline in motors designed for a speed of 60 or more miles an hour when perhaps at no time in the life of the car is it ever advisable or necessary to use the motor's maximum capacity. The fuel substitutes as volatile as gasoline, (other than that made from shale oil), can at the utmost reach only about one-fourth[4] of the demand for gasoline in 1919.

The shale oil industry is not likely to produce oil in sufficient quantities to affect the price movement in the near future. In the first place the initial investment required is enormous and will not be forthcoming in large volume until the profitableness of the industry is unmistakably attractive.

The progress of recovery of oil by sinking shafts and driving galleries is to be observed. It will not affect the market in the period covered by the valuation of the average holdings. Nevertheless it will be a factor in some future time. The French (formerly by Germans) demonstrated the practicability of mining oil in this manner.[5] Undoubtedly with improvement in methods it will not be an uncommon sight to see oil-sand tipples where derricks now stand.

So far, a relation between the movement in the price of other commodities and of crude oil can be noticed in spite of the unrelated movements in price peculiar to oil. Thus the various index numbers from reliable sources should be followed. Commodity price movements of all kinds are best reflected in these indices.

It has recently been shown by Holbrook Working[6] that the price of commodities bears a relation to bank deposits. The Federal Reserve System, having in its control about a third of the banks of the country, supplies in its publications a suitable source for these data. Incidentally, the same writer demonstrated that for the last century the price movement in Great Britain, a country with currency on a gold basis, followed very closely the fluctuations of our prices.

The opinions of economists and students of finance should not be overlooked.

It is wholly impossible to list all the factors affecting or likely to affect the future price. The insignificant factor of today may be a fundamental consideration a few years hence. In any estimate of what the further course of prices will be, the chief factor that must be taken into account is the general trend about which the price fluctuations in the past have moved. In order to study this general trend an analysis of all pertinent commodity prices, production, data, and other previously mentioned historical factors must first be studied with their influencing factors. Furthermore, since oil and gas are wasting assets and subject to depletion they are less subjected to this general trend of price movement when the demand equals or is greater than the supply.

Regional Influences: The fundamental factors affecting price changes vary geographically. The Mexican producer is greatly interested in the political situation, while the Appalachian producer observes more closely the gasoline market, and in California the prices of fuel oil once depended greatly on the price of coal in that state. Heretofore, the price in the Appalachian field had considerable influence on all other grades in the country except the Californian. But now the price in the Mid-Continent field, because of its large production now controls the situation with respect to prices on the other grades of oil.

Normal Price and War Inflation.—The Bureau of Labor and other price indices indicate the winter of 1915 as the starting point in the country for the increase in price originating through war conditions. Due to the 1914-1915 depression, the price of crude in relation to 1913 is 80 while the average of the Bureau of Labor's selected list of wholesale commodities is at 100 in November, 1915. Thereafter, the rate of increase in both was the same but it was not until the rapid increases in 1919-1920 that the price of crude recovered from its lag of twenty points.

The drop of Pennsylvania crude to \$2.25 in 1921 is relatively equivalent to \$1.35, the lowest 1915 price, when taken

3—Pogue, Joseph E., Future Demands on Oil Industry of the United States: Bull. A. I. M. E., 1922.

4—Ambrose, A. W., Cal. Oil World: Vol. XIII, No. 662, May 26, 1921, p. 82

5—A preliminary study of the recovery of oil by sinking shafts and driving galleries, by Louis Franklin, Bull A.A.P.G., July-Aug., 1922, pp. 344-8.

6—Working, Holbrook, The Annalist: Vol. 17, No. 441, June 27, 1921, p. 686.

in terms of other commodities, since these have not been deflated to the extent of crude oil prices. By the expression of all prices since 1915 on a basis of 100 for that year a relation is obtained between inflated and normal prices. However, such procedure always includes an increase through normal changes which should be determined to get the true amount of inflation.

A diagram, fig. 24, shows that after the elimination of inflation, the price was never over $2.50 except for about six months. The oil producer sold, in relation to the 1913 price, 40 per cent below the average of other commodities during most of 1914-1915, and thereafter the price of oil lagged 20 per cent behind the price of other commodities until May 1920, when they recovered to the level enjoyed by other products, only to drop below again in a few months. Operating and development costs are still somewhat inflated (Dec. 1922) and may remain so while the selling price is deflated below pre-war level. Until such a time as crude oil prices and those of other commodities fail to show similarity in their rates of fluctuation, the indices will aid in determining whether any change is contrary to the general market conditions.

In making predictions during periods of inflation, the price increments should be divided into normal and inflation advances. The normal increase is that found under stable pre-war or other normal conditions, and the inflated is the amount of change in value of the dollar. This latter cannot be expected to continue at the same rate and direction with respect to the normal. Many economists predicted only a small deflation for the post-war period and expected the value of the dollar to remain somewhere near the peak level. However, the lack of precedent for a condition such as that found after the world war where all the nations in the world were economically affected made all predictions unsafe. The dollar has deflated in value but in recent months the rate of change has moderated so that it appears probable that a lower level will **not** be reached in the near future by the general trend line.

Historical Influence on Price Increase.—Perhaps no better method can be found to observe the effect of over-production and other factors on price changes than to plot the posted prices on quadrille paper and mark the probable cause for each notable feature.

Long and Short Period Prediction.—If the aim is to postulate the price for the immediate future, the minor oscillations from the average line and the present market conditions should be the controlling factors. The price may be above or below the average line and consequently will greatly alter the calculation of a property if the bulk of the oil is recovered before an average series of prices can be applied.

For the purpose of ascertaining the rate of change for a long period of years, a smoothed line through the irregular one based on history to date, and modified by probable influencing factors is advisable.

The Average Line of Increase.—The average line of increase is not always a straight line. Where such is the case, arith-log paper offers the most satisfactory means of making a smoothed line. It is generally best to use quadrille paper to determine the exact position of the average line and then to transfer the information to the arith-log paper for extrapolation if that seems warranted. That an exponential rate of increase will apply in the future is not at all improbable in view of the present supply and present market.

The Average Price Line in Relation to Well Decline.—All predictions of prices on an average line are on the assumption that future production will be at a uniform rate. This is a fallacious assumption when one is attempting to determine the prices to use for a valuation. Firstly, the production is recovered at a declining and not uniform rate. Secondly, the prevailing price on the date of prediction is generally above or below that for the same year as found by the average line. Should the posted price be above the average line of increase as of date of valuation, it is evident that the valuation, if predicted prices are used, would be low and the opposite where the posted price is in the trough of a price cycle.

Reliability of Price Estimations.—The reliability of the price estimate depends in the first place on the capability of the estimator, and secondly upon the stability of conditions. Reference to past predictions of various kinds by responsible authorities leads one to believe that it is not safe to rely too much on postulation. Financial journals, books on economics, and other publications make numerous predictions based on the deliberate study of men of international standing in their profession, yet even these predictions have often failed to materialize. The difficulty is greatly increased when no precedent for conditions expected has ever existed. Such is the situation, in part, in the oil industry at the present time. However, predictions must be made. It is desirable that more studies of future price should be published as a freer exchange of ideas as to future prices and the factors influencing them would result in safer predictions to all operators and would be especially helpful in formulating plans for the future.

Discounted Future Price Table.—Under the discussion of future gas prices, is given a table showing methods of price interpolation and of discounting which will facilitate valuation work.

Gas

The study of prediction of gas prices must be divided into two parts, (1) that known as dry gas and, (2) that yielding gasoline. The latter is discussed in the chapter on valuation of casinghead gasoline while the part to follow is on natural gas produced and sold for lighting, heating and power.

Gas prices are not as difficult to predict as those for oil, as oscillations are less frequent and the influencing factors are less violent. Opinions on prices often vary in accordance with the investigator's relation to the company for which the predictions are being made. Company officials are generally much more optimistic than a disinterested party, whereas commissions appointed for the fixing of rates are likely to be more or less pessimistic. Any price prediction should stand on the facts surrounding the past and probable future conditions, irrespective of unfounded opinion.

As mentioned previously, a gas company may be divided into several parts, or systems. Where valuation is for one branch of the operations only a distribution of consumers price to that branch is necessary. The federal government has held that the appraisals of natural gas properties for the purpose of depletion, deduction in taxation must be on the price per M. cubic feet at the well. There are only a few large gas companies that do not transport and distribute their own gas. Consequently, some method of distribution between departments of the price charged the consumer must be devised. It is evident that any such splitting of the sales price to find the proportion attributable to the producing department would likewise divide the going concern value. The consumers price is the result of the whole combination and yet more especially that of the department developed to market the product. Without this department, it is probable and in many cases certain that less profit proportionately would be realized. The amount of going concern value depends largely upon the possibility of marketing the gas in the field. Many producers could sell direct to companies whose supply is becoming exhausted.

Distribution of Consumers Price to Branches of the Plant.—Where the valuations to be made are for the production in the field and the company markets its own product, a method of pro-rating the sale price per M. cu. ft. to consumers must be found or else the field price be

$$\frac{\text{Am't of depreciation per annum of distribution plant + distribution operating exp.}}{\text{Total depreciation, depletion and operating expenses per annum for company}} \times \text{Consumers price} = \text{Share of this price to distribution system.}$$

$$\frac{\text{Am't of depreciation per annum of transportation plant + transportation operat. exp.}}{\text{Total depreciation, depletion and operating expenses per annum for company}} \times \text{Consumers price} = \text{Share of this price to transportation system}$$

$$\frac{\text{Am't of depreciation and depletion per annum of production plant + prod. oper. exp.}}{\text{Total depreciation, depletion and operating expenses per annum for company}} \times \text{Consumers price} = \text{Share of this price to production system}$$

established by other means, such as prices paid in the field by the company for the gas purchased. One method that has been used to distribute consumers price is as follows:

$$\frac{\text{Distribution plant investment} + \text{average annual distribution expenses}}{\text{Total company investment} + \text{average annual expense}} \times \text{Consumers price}$$

$$= \text{Share of consumers price to distribution system.}$$

$$\frac{\text{Transportation plant investment} + \text{average annual transportation Operating Expense}}{\text{Total company investment} + \text{average annual expense}}$$

$$\times \text{ Consumers price} = \text{share of consumers price to transportation system.}$$

$$\frac{\text{Producing investment} + \text{average annual production operating expense}}{\text{Total company investment} + \text{average annual expense}} \times \text{Consumers price}$$

$$= \text{Share of consumers price to producing system}$$

This method of division disregards differences in rate of amortization. The investment in transportation system is not likely to require as high a rate of depreciation as the producing system. The rate of return or redemption of investment should influence the price distribution. The capital tied up in transportation equipment may be twice that in the producing equipment, but the former may have only half the depreciation rate of the latter and consequently will require less redemption per dollar investment. Proper discretion must be exercised to avoid unreasonable allocation of price fractions and the incorrectly balanced valuations that would result. The operating expense of each division must of course also include the pro-rata share of general overhead expense.

The easiest distribution to employ and perhaps the most just is on the basis of depreciation, depletion and operating expense. Depreciation and depletion are a return of the investment and depend upon the life of the property in question. As a rule, a company with a well established accounting system will have fixed rates of depreciation for each class of equipment based on experience of long standing. No better redemption of capital rate could be desired. Thus, the amount of depreciation and depletion of any branch of the plant, plus its operating expenses, including its share of overhead expense, as compared with the totals of depreciation, depletion and operating expense for the whole company, gives the proportion of the sale price, which, if applied to this branch, would allow a return of investment, pay expenses and yield a profit commensurate with the redemption fund and expenses. The general plan of distribution would be as shown in the table at the bottom of the two columns on page 38.

The depreciation, depletion and operating expenses can be the amounts for the current year or the average per year up to the date the price division is desired. The average is not as likely to yield so accurate an allocation as the current amounts would, since the consumers price may be high for a given year on account of conditions that affect one of the divisions especially. For similar reasons, the expenses in that division are likely to be correspondingly high, and will be thus compensated.

Three divisions, namely, producing, transportation and distribution have been shown. There is generally recognized a fourth which is exploration. This is a non-income making branch and comprises bonuses for undeveloped leases, rentals; legal, engineering, and geological expenses incident to the obtaining of leases before production commences. No amortization rate can be definitely attributed to this investment unless a producing life can be established for the lease. Some leases will have a short life and will be soon dropped because they are not as promising as had been hoped. With a prospect of developing the holdings, for they are usually acquired for this purpose, the possibility of writing this cost off as depletion must be considered. The smaller the company, the less distinctive is this refinement, as many small companies acquire tracts and develop them immediately. Again, it is contended by some that reserve acreage being an essential to continued production should not be separated therefrom. If the small bonus and rentals paid are not charged to expense on the books, then a percentage of investment amortization should be assumed. Since undeveloped leases are necessary to maintain production and the investment therein shows no income until the properties are proven productive, a separation has generally been ignored and in consequence the fourth division or exploration is combined with the producing system. Of course, by this action the producing wells are given a greater value by reason of the increase in the share of consumers price. But, on the other hand, the expenses are increased and only the pro-rata profit increase, caused by this process, is reflected in the valuation. Since exploration and development are not directly income producing, the cost of leases must be borne by the production department, if classified as part of this system. The developed and undeveloped acreage on any one lease is too closely related to warrant a separation along lines mentioned above.

When the producing price is derived from the consumers price by allocation it often contains a certain amount of going concern value. As previously stated, this portion thereof must be ascertained and eliminated for certain types of valuation, yet retained for others.

Adjustment of Field Price Because of Line Loss.—The amount of gas produced in the field is greater than that ultimately sold to the consumer. The total difference varies with many factors and often runs over thirty per cent. Where a well price has been determined by the allocation of the consumers sale price, an adjustment must be made to well price to avoid too great a portion of the total sale price going to the producing end, on account of the line loss. This occurs where it can be assumed that a purchaser of gas in the field will have in mind subsequent losses and therefore pay a correspondingly smaller price. The loss is thus foisted upon the producer. Such a condition is more to be expected in a non-competitive market where circumstances limit the opportunities to dispose of the supply.

One of three things can be done; (1) The loss can be distributed over the three systems in a proportion similar to that used in the allocation of the sale price or, (2) the loss can be assumed by the producing system alone; or (3) when the combined holdings of a producing and marketing company are to be valued the loss can be ignored by use of the sale price to consumers. The choice depends upon the degree of competition and the demand for the product. The greater the demand and the less the supply, the more likely the marketing company is to bear the line loss. Where the possibilities are uncertain distribution of the loss would be the fairest. In the third case the well production must be corrected in accordance with the amount finally sold. Thus gas lost is eliminated from all computations as though it had never existed.

Factors Affecting Price Increases.—Natural gas, unlike other natural resources, must be considered a public service and not a commodity to be sold. It is a public service in two respects; one in that the people are receiving something for a price far below its real value to them as compared with artificial gas, for instance; the other, that it provides at all times a supply for a demand that varies both hourly and seasonally. Furthermore, it is practically the only natural resource the price of which is fixed by Public Utility Commissions.

The attitude of future Public Utility Commissions will be an important element in affecting price increases. Their practice thus far has been to permit a gas company to earn a certain per cent on the investment, the rate being usually about six to eight per cent. As the investment and expenses increase, a higher sale price for gas is fixed, but only after repeated and expensive contests before the Commission. Probably the attitude of these bodies will have more influence on the future price of gas than any other factor. However, these commissions can not deny what has some semblance to a reasonable profit to the operating companies. Consequently an estimation of future costs will help to serve as some guide to the future price. With the reluctant attitude of their constituents ever in mind the gas companies will in any event obtain only slow and steady, but nevertheless inevitable increases in price. A point of great difficulty is that all commissions do not adequately recognize how considerable are the items of risk and depletion in the natural gas industry.

On the other hand, the producer faces numerous factors which necessitate an increased income, chief among these being the constant exhaustion of the supply.

The next factor to consider is the demand. If we assume that the price of

natural gas remains constant or nearly so, it is obvious that the demand by the consumers would naturally increase. This is especially true of industrial gas, for most established industries continue to expand. Then too, the increase in population means a greater number of domestic consumers. To offset this in part, there is greater efficiency in transportation and more successful elimination of waste in the use of the gas. The public is rapidly being educated to the proper use of gas. However, there is a limit to the degree of efficiency in utilization likely to be obtained.

Still later in the history of a typical company, as the supply wanes and the price advances, the number of users decreases. This is generally accomplished by first shutting off the industrial consumers in the winter and later shutting them off altogether in order to conserve the supply for domestic use. Such action necessitates the company's increasing the price of domestic gas to offset its loss of income by the commercial curtailment; for industrials are for the main part a year around load and domestics are a fractional year's load. Furthermore, industrials being large consumers on one meter are cheaper to supply per foot of gas.

Consumers using gas for heating purposes will use coal where the direct economy thereby offsets the greater cost for the cleanliness and the convenience of the gas. For the same reason, however, this increases the cost per foot of gas furnished to the remaining market, since the small domestic consumers are supplied at greater cost per M cubic feet.

As the supply of gas becomes less and as the price of gas becomes higher, artificial gas will be mixed with the natural gas. Of course the price would have to be increased to warrant the expense of mixing to any great extent, except in a few regions where coke is made with cheap gas by-products. With mixed gas, it is universally recognized that the thermal units per cubic feet are greatly reduced.

As a rule, the factors influencing price will vary somewhat with each company. For instance, here is a company which showed that up until 1920 the following changes were taking place.

1. Average depth of new wells is increasing at rate of about a hundred feet per annum.

2. The proportion of dry holes is increasing at the rate of two per cent per annum.

3. The proportion of dry holes on offset locations is increasing at the rate of about three per cent per annum.

4. Reserve acreage per consumer is decreasing at the rate of two per cent per annum below the 1905 amount.

5. Developed acreage per consumer has been steadily decreasing each year.

6. The number of consumers is increasing at the rate of twenty per cent per annum over the 1905 amount.

7. The average time for wells to be turned in the line has changed from five months to eleven months since 1900.

8. The average initial closed pressure of new wells is declining at the rate of thirty pounds a year.

9. Production per acre is decreasing nearly three per cent per year below the 1905 amount.

10. Production per well has been steadily decreasing each year.

Some of these changes are the outcome of others. For instance, the developed acreage per consumer could not have been allowed to decrease if the wells were still turned into the line only five months a year. However, since the maximum time possible in the line has nearly been reached an increase in the developed acreage per customer is needed, in accordance with the decline in production per acre, although it will not always be obtainable.

With these facts and conditions, it is not at all unreasonable to expect a price increase for this company, at a rate greater than in the past. The actual rate of increase depends more upon the possibility of legal regulations for conservation that would limit the distribution of gas to domestic consumers and would perhaps reach even further by prohibiting its use for heating. But a change likely to occur several years hence will not affect the final results nearly so much as an immediate change. For this reason, it is often better to base the future prices mainly on the history of the past and disregard those factors the magnitude of which it is impossible to estimate.

Heating Value Advantage of Natural Gas Over Artificial Gas.—Neither the consuming public nor public utility commissions have yet fully realized the advantages of natural gas over its manufactured substitute. The chief advantage is its greater fuel value. The following figures represent averages of the heating values in B. T. U. per cubic foot of natural gas and the various manufactured gases:[7]

	per cu. ft.
Natural gas	1,100 B.T.U.
Oil gas	640 B.T.U.
Retort coal gas	600 B.T.U.
By-product coal oven gas ..	575 B.T.U.
Carbureted water gas	575 B.T.U.

Aside from this advantage, natural gas, being free from sulphur, is non-poisonous, and, with rare exceptions, does not have an objectionable odor.

It may be assumed that natural gas may in turn reach the price of artificial gas and exceed it, in view of its aforementioned claims of superiority.

Prediction Curve.—No particular type of graph can be chosen as typical of the increase in price. In a few instances the graph may be an exponential curve, and if so, arith-log paper serves better for extrapolation. In general quadrille paper will cover most cases. It is best to plot the weighted average prices received in the past. The average line should be so drawn that the total area beneath it and above a line connecting prices to the date of the last given price equals that above the average line and below the line through the price points. By continuing the line along the course begun, an extrapolation of the future price is made based on the facts to date. Given the average line as the fundamental tendency, an increase or decrease therefrom can be inferred in accordance with the other things observed. Certain of the factors have been influencing the price in the past and so should not be further considered. The change in production per well, acreage per well, risk of dry holes and others with their resulting increase in cost of development have necessitated changes in prices. Some however, have a "criti-

7—Weyer, S. S., Value of Service as a Factor in Public Utility Rates with Special Reference to Natural Gas Rates.

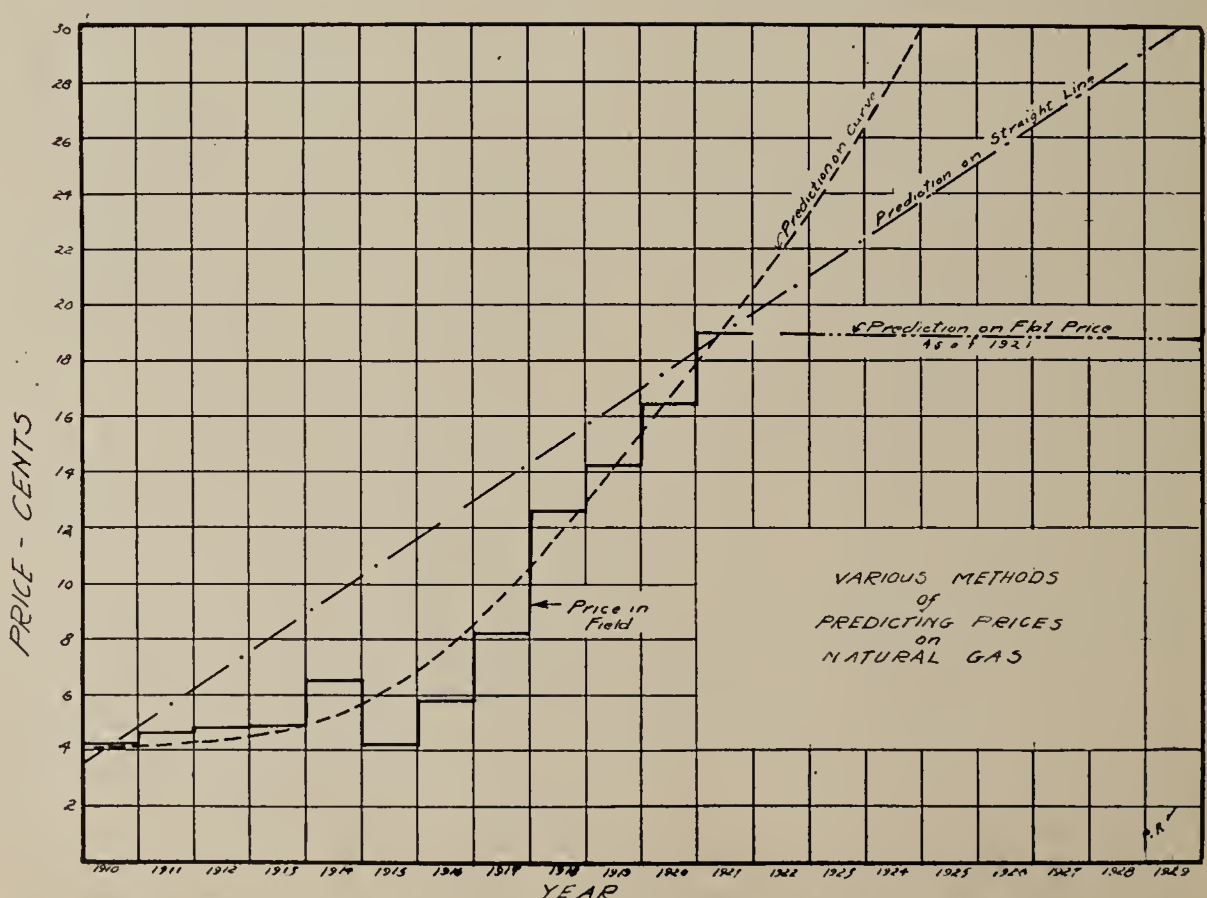


Fig. 26.—Three types of price predictions on the same information (After Ruedemann)

cal point" which passed will cause a greater rate of change than in the past. Among others, the time the well is turned in the pipe line and the time of the peak production are worthy of mention.

The diagram, figure 25 illustrates the weighting of the line and the extrapolation. In this particular case, the company's records indicated the possibility of a change in rate of increase of one-half of one percent per year over the year prior. This was determined by computation from the factors that are going to affect the future trend. Some of these are new and have so far had no effect on the price movement; others indicate that they will be more effective in the future than in the past. Any factors, in which the change is uniform or nearly so, automatically, by their past influence on prices, affect the direction of the average line.

The true line of advancing price cannot be used for all types of appraisal. At the present time the Federal Government is holding gas companies to a straight line increase when making valuations for depletion purposes. This is shown by the dot-dash line in figure 26. Furthermore, some rate fixing bodies are denying any increase whatever on the principle that to do this establishes a valuation about which the necessity for change in rate is to be contested. In other words, the presumption of an increase is taken us the basis for a higher rate. On the other hand, with the decreasing supply and the ever increasing cost of exploration and operation, denying the companies the right to increase the gas rate is manifestly unjust and would be ruinous to the industry.

For rate-making the flat price, false and even ridiculous as it is, seems to be the one required by some Commissions. A prediction curve on the actual history of price fluctuations is shown in figure 27 for the purposes of comparison.

War Price Inflation.—Although war inflation was not as evident in natural gas prices as in other commodities, a certain amount of inflation has occurred. This has crept in with the increasing costs and with the consequent necessity for a greater return.

By it a situation is created more complex than for any other commodity price. The rapid change in the supply and in the market, combined with incomplete inflation in comparison to other things, makes predictions as of war years and post-war years a hazardous task. Prices are regulated by operating expense and investment. The bulk of operating expense is labor. The cost of this will gradually decrease, but to offset this, the amount of labor required to produce a uniform amount of gas each year will increase. Cost of labor will not decrease as rapidly as will commodity prices, for labor always lags behind in its deflation. It is hardly likely that a decrease in the cost of materials will offset the requirements of increasing investment to retain a uniform yield.

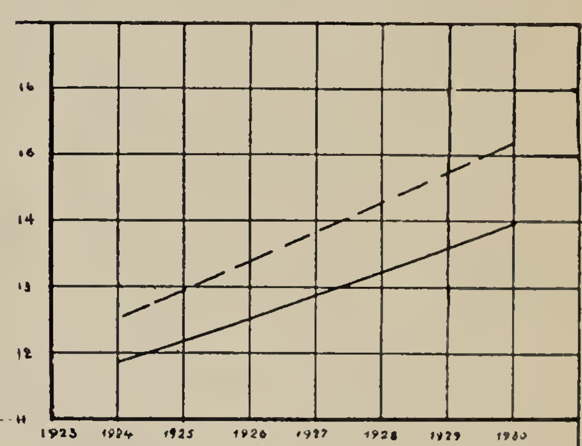
Effect of Gasoline Price on Natural Gas.—In pools where the gas contains gasoline in commercially extractable amounts, the same should be taken into consideration in the valuation. This can be done by (1) increasing the price of natural gas for appraisal purpose, by the amount of profit expected from the gasoline; (2) valuing the gasoline income as a separate branch; or (3) adding the sale price of the gasoline produced from every M cubic foot of gas produced to the price of the gas and making allowances for plant depreciation and operating expenses in the costs of gas operating.

Treatment of Gasoline Plant Operating Expense.—When operating cost is being subtracted from the gross revenue and the profit on gasoline per M cubic feet of gas produced is determined and added to the natural gas sale price, then the operating expense has a direct effect on the natural gas price. The price will be further influenced by the choice of method used in computing the depreciation of the gasoline plant.

Where the amount of available gas for gasoline extraction is limited, the depreciation on the plant should be commensurate with the decline in reserves, that is, it should be distributed proportionately over the gallons of gasoline produced each year. The building of a depreciation reserve by a uniform annual amount may place an unwarranted burden on the expenses of the plant at the time of small production in later life.

The most comprehensive and soundest way to value holdings for their gasoline content is to consider separately the value derived from this product. The present value of such returns can then be added to the value found for the holdings on the basis of the revenue from natural gas alone. (See chapter on Valuation of Casinghead Gasoline.)

Prediction of Prices for a Short-Lived Property.—The discussion in connection with average curve prediction is more important when postulating prices for a number of years hence than when for the immediate future. It may be permissible to omit price predictions entirely when valuing properties the life of which will not extend far beyond the probable continuance of the current price. Even though an increase in price may be inevitable a few years hence, the appraisal will not be far wrong if current price is used throughout, because the decline in production may reduce the error to a small percent of the total value. Furthermore, where price is likely to fluctuate in both directions and the life will be short, it may be more practicable to assume a flat price at the level of a past average or the latest price, than to attempt prognostication. The most recent price should always be employed to start with as the greatest recovery of gas is in the early years, discrepancies in judgment on price for those years will introduce large errors.



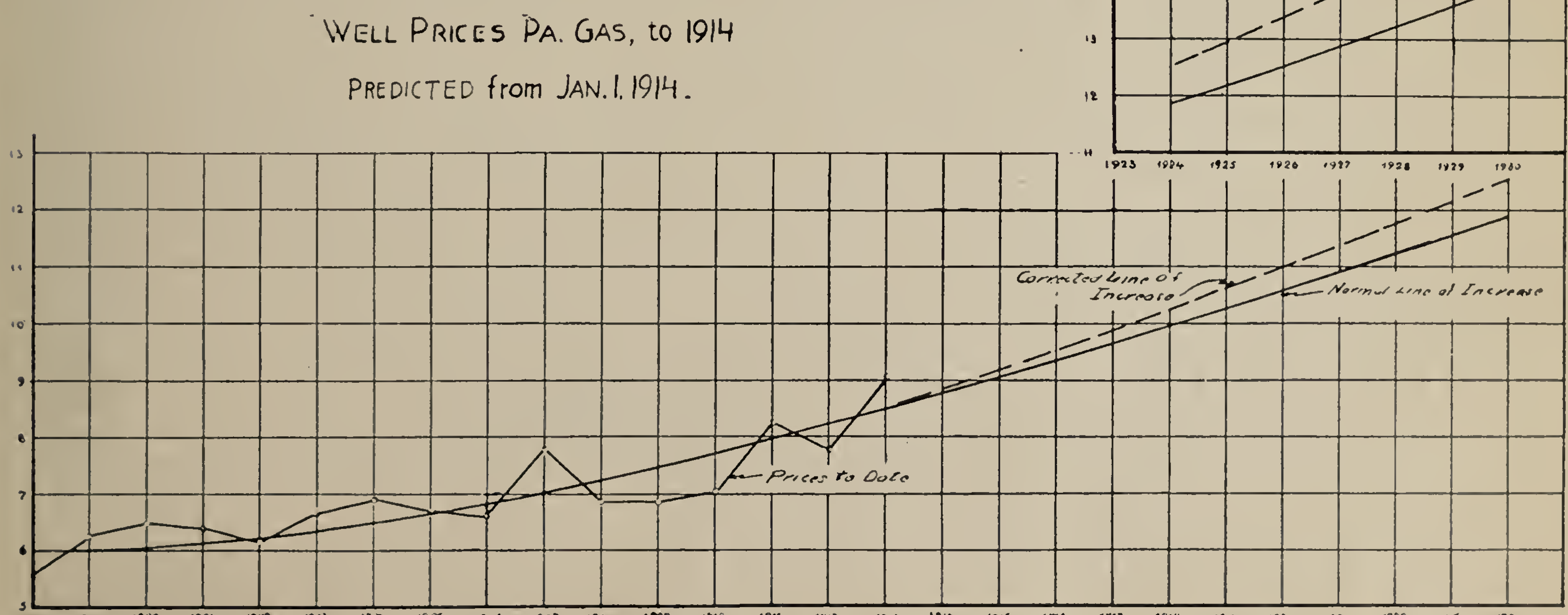


Fig. 27.—Method of predicting future prices on basis of equal areas. Line of increase is corrected to provide for other influences not effective in the past.

Appraisal Of Oil And Gas Properties

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Chapter XI
PREDICTION OF FUTURE OPERATING COSTS
Oil or Gas

DEFINITION.—Broadly speaking, the cost of operating for oil is the expense necessary to recover the product from the underground reservoir, but for gas this item includes the cost of distributing to the market.

Item Omitted from Operating Cost.—Items chargeable to investment must be excluded. Repair expenses are those replacements that merely maintain the life of the property. Additions to the equipment and replacements that materilly lengthen the life of the physical property are investments. Also, the drilling of wells should not be included in the operating expense. The development on undrilled wells is dealt with separately. Depletion and depreciation are redemption of capital and, although deductible from the gross income to obtain the net income, are not regarded as legitimate operating expenses in analytical appraisal. Cost of dry holes and lease expenses on undeveloped leases are also omitted.

General Overhead Expense.—General overhead expense embraces items that are too broad in application to be assignable to any particular unit. These generally include telephone lines, telephone offices, field offices, warehouses,' legal, geological and engineering services; bookkeeping, executive expenses and taxes. Some of these may not always be classed as overhead, as for instance, the expense of the geological department may be chargeable to the production division but still be overhead expenses in cases where distribution to a particular well, tract or lease is done by arbitrary allocation.

Oil

Operating Cost Items.—In making an analytical appraisal of producing properties, not all expenses on the lease are used to determine the operating costs. The following classification is generally found useful in finding what items constitute operating expenses:

1. Superintendence.
2. Labor on operating wells.
3. Ordinary repairs on wells in the nature of maintenance rather than investment.
4. Ordinary repairs on power plants and other buildings and fixtures not in the nature of investment.
5. Miscellaneous operating and maintenance expenses.
6. Share of general overhead expense.

There is considerable difficulty in separating true repair and expense items from investment items. Though there is no definite dividing line, the appraisor usually classifies those replacements that increase and prolong the original life of the oil property as investments, while those that merely maintain the original life of the property are classed as expenses. All investment items come into consideration as derived from depletion and depreciation allowance and must be excluded from the operating cost used in the appraisal. Aside from the lifting and other well expenses ataching to the operation of the lease, there is the general overhead, which covers the main office, clerical work, telephone lines, executive and many other expenses not applicable to any one well or lease but to the whole plant.

Distribution of Operating Expenses.—Where companies have no separate lease accounts, the total cost of operating is usually pro-rated by wells, no distinction being made as to the amount of production or the age of the well. This is a simple and effective way to get an average. Still another method commonly used is to apportion the expenses over the number of barrels of production. This is an incorrect means of allocating costs in an appraisal. The average well year cost has but little relation to the amount of production, in fact other things being equal, the annual cost would show little fluctuation from one year to another. Because it costs ten cents a barrel to operate when the well is yielding ten thousand barrels a year is no indication that it will cost at the same rate, or a total of ten dollars per year, when the well is giving only one hundred barrels a year.

Share of General Overhead.—Each well should bear a share of the general overhead expense as previously defined. The distribution is preferably by wells and not by production. The Oil and Gas Valuation Section of the Internal Revenue Bureau in the Manual of that unit, suggests this method of distri-

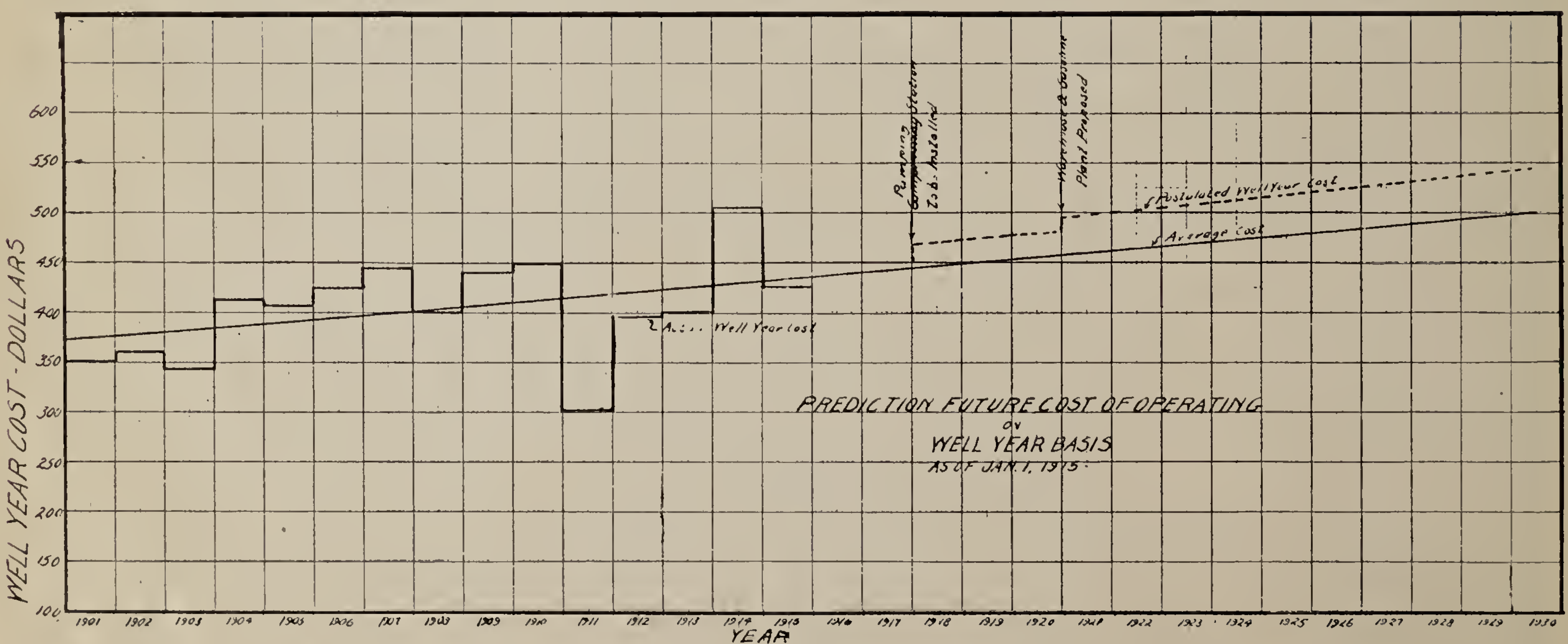

Figure 28.—The method of equal areas for predicting future operating costs. In 1918 the cost is increased to provide for additional equipment to be installed. (After Ruedemann.)

bution of expenses, where no separate well or lease accounts are kept.

Prediction of Future Operating Costs.—A tabulation of annual costs for a number of years, preferably extending several years before the war, is desirable. In the absence of such definite information, an estimate of costs by analogy is substituted. Having secured the costs, reduce them to a well year basis. plot on coordinate paper and find the rate of change. (The use of well-year costs in preference to barrel costs is suggested as being the more accurate.) This plotting may be done to better advantage in some cases on semi-logarithmic paper. Figure 28 shows a cost of operating prediction line, in which price inflation is not a factor.

Cost of Operating and War Inflation.—The war has caused an abnormal increase in the cost of living in general. Wages have increased over one hundred per cent in many cases. With unsettled conditions during the war and several post war years, the prediction of costs becomes extremely difficult. Those cost increases known to be inflation increases should be dealt with independently when predicting. The use of index numbers such as those of the Bureau of Labor, Dun's or Bradstreets, assist in ascertaining the amount of inflation.

Probable Post-War Change in the Value of the Dollar.—By finding the price changes of various commodities up to the present time, it seems apparent that there is no uniformity in the amount of deflation. The curves in Figure 29 are present to illustrate the irregularities in price deflation for materials and labor which have a bearing on petroleum production. For comparison, the price of Pennsylvania crude is used, but the relation would be analogous for other grades. The solid heavy line represents the percentage relation of the price of Pennsylvania crude at any given date to that of 1913. The dot-dash line indicates the percentage change in wages of New York state factory workers in relation to the June 1914 wage. The dotted line gives the inflation of lumber and building materials in percentage of the 1913 average price. The dashed line shows the same thing for metals and metal products. All data except the indices for crude oil were taken from the Bureau of Labor statistics.

The chart (Fig. 29) very forcibly demonstrates the handicaps under which the oil producer is operating. The price of oil has been completely deflated for most of 1921 and is about 50% above the 1913 mark. On the other hand, in April 1922, metals and metal products carry some 16% of inflation and lumber and building materials are still 102% high or more than double the 1913 cost. Assuming the labor scale of the New York state factory workers to be representative in so far as the deflation is concerned, the figures show that labor is equally as high as lumber in proportion to the normal price. Further, the average of all commodities must be deflated 51% of the amount in 1913 or 33% of the present average to return to normal. The arrow on the chart marks its approximate position in February 1922.

There is a possibliity of the various groups maintaining different levels of price to the pre-war standard and industry accustoming itself to the change. It would mean the acceptance of a different margin of profit per barrel from that formerly taken. However, a large variation is hardly to be expected, for the present tendency seems to point toward stabilization.

Costs of Operating the Future Extensions of the Plant.—Where it is evident that future extensions of a plant will be necessary to recover the production, provision is to be made for such additional costs. Vacuum plants or other installations essential to increasing or maintaining the production come under such future extensions.

Table of Cost of Operating.—Several types of tables for operating costs may be used for the efficient compilation of an appraisal. One table is that of future costs as found on the curve. This one can be arranged in greater detail where various information for the appraisal is necessary, as for Federal Taxation. Another table is that of costs discounted at the rate being used in the valuation computations. This step may save considerable work. (See Chapter on Appraisal Computations.) A third table would comprise a series of totals of costs already discounted for any number of years. An example of the first type accompanies this chapter.

Gas

For gas cost prediction the separation of operating costs becomes more difficult for in addition to the customary items it is also dependent upon the scope of the appraisal. There are usually three systems to a large gas company, namely, producing, transportation and distribution. In this chapter the discussion refers mostly to prediction of future operating costs for the producing system. Consequently the term "operating costs" will refer to this system unless otherwise stated.

Operating Cost Items.—In general the following will be found under operating expenses for the whole plant:

Producing Expenses

Superintendence.
Labor—Operating wells.
Gas Well Royalties.
Ordinary repairs to wells not considered as investments.
Ordinary repairs to buildings and fixtures not considered as investments.
Miscellaneous operating and maintenance.
Share of general office overhead.

Transportation Expenses

Superintendence.
Labor in transporting gas.
Line repairs.
Compressing station repairs.
Miscellaneous transportation.
Share of general office overhead.

Distribution Expense

Superintendence.
Taking meter readings.
Collection and service office expense.
Distribution line repairs.
Buildings and office fixtures repairs.
Miscellaneous items.
Share of general office overhead.

Operating Expense When Valuing Systems in One Group.—If a very gen-

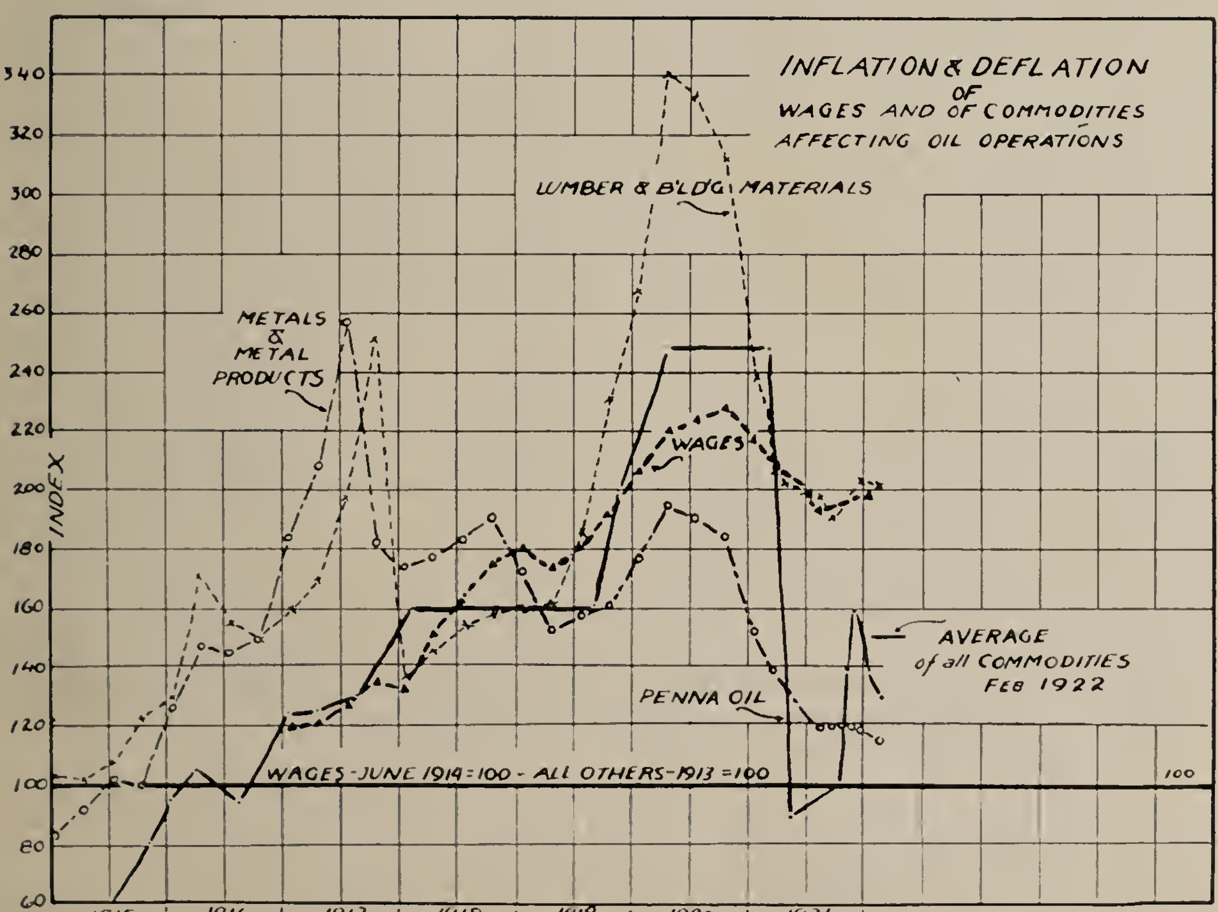

Figure 29.—Chart showing the price changes in relation to the 1913 price and their relative positions at the beginning of 1922. Wages, June, 1914,—basis 100 units; all others, 1913—basis 100 units. (After Reudemann).

eral appraisal is being made, one merely on the total gas likely to be sold annually, then all system allocation is ignored and the operating expenses will be the sum of that found for each system. The separation of overhead expenses as discussed above is irrevelant in this case. The total expense is divided by the amount of gas or the number of producing wells, whichever unit of expense reference is being used.

Cost of Operating by Individual Properties.—An appraiser can be most accurate in his estimates when the accounts are kept by individual properties. If this information is available, the cost predictions can be carried out in a general manner, first to obtain the rate of increase or decrease to be expected and then to apply those rates of changes to the costs for the individual property. The pro-rata share of general overhead applicable to each tract will depend upon the size of the property. The number of wells reflects this relation best.

Operating Costs Not Yet Encountered.—In any prediction of operating expenses, due consideration should be given to changes likely to be required in the plant. One change in particular that should be anticipated is the installation of a compression plant which usually becomes necessary when the closed gas pressure is insufficient to deliver the gas to the pipe line. The operation of this plant will be, of course, an additional expense which must be added to the predicted expense based on past experience. Another instance is where a transportation system may contemplate building compressing stations along the line, or a telephone line into a district not yet reached. If a gasoline plant is proposed and the receipts therefrom are to be combined with the natural gas receipts, then the expense applying to it should be added to the operating expense used in valuing.

The possible future expenses above those predicted on present normal assumptions are too numerous to list and depend entirely upon the extent of operations and the completeness of the present plant. With more efficient installations or methods, one may anticipate lower operating costs in the future.

Operating Cost in M. Cu. Ft. or Well Year.—The choice of units depends upon the degree of accuracy desired in the appraisal. To reduce the operating cost to M. cu. ft. is less accurate than on a well year basis. The present production is from a certain number of wells. It is not at all likely that the same amount of future production will come from a similar number of wells. Cost of operating the production system is related more closely to the number of wells than to the gas produced during the year for the following reasons: (1) Well rentals constitute the greatest operating expense; (2) the increase in the number of wells necessary to maintain production is a heavy item; (3) valuation cannot be made on a drilling program commensurate with past practice because of changing risk. The last named is probably the most important consideration. In placing a valuation on future yield, an estimate is made of the anticipated production from each well. The commercial life of a gas well sometimes extends to twenty years. All wells producing on date of valuation enter into the operating costs. These same wells as a group will continue to produce a number of years. The operating expenses incident to securing production from them will remain dependent upon the number of wells rather than the production. Consequently, as the production declines, the operating expense per M. cu. ft. mounts up at a much greater rate than the prediction on M. cu. ft. basis would indicate. Where the purpose of the appraisal demands rapid coarse work, the M. cu. ft. method is necessarily employed. If well year cost is chosen, it can be carried through as such in the computations or reduced to M. cu. ft. by years. To reduct to M. cu. ft., estimate the future yield each year for the wells being appraised. Next, multiply the predicted operating cost for a well year, for a designated year, by the wells to be in use each year and divide the result by the annual yield estimated for each year. Thus the future cost of operating is found in terms of M. cu. ft. by years. This can be subtracted from the price predicted per M. cu. ft. and a net future revenue obtained.

Graphic Method of Predicting Future Operating Expense.—The procedure in graphically predicting operating costs is similar to that used for future prices. The past, or historical costs, are plotted to date and a weighted average line is drawn through the points. This line extrapolated gives the locus about which the future costs will fluctuate. In time of normal conditions, it is hardly necessary to deviate from the extrapolated line except where expenses for a new purpose are to be added

A diagram, (Fig. 28) shows a prediction made as of Jan. 1, 1915 for a certain large gas company. It is on the cost of operating in the field and for the purpose of evaluating the production system. The broken line indicates an allowance made for yearly operating expenses on a compressing station and warehouse contemplated in future construction plans.

Discounted Operating Cost Predictions.—In order to eliminate a step in the final computations, the cost predictions can also be discounted and placed in tabular form. With the prices discounted in a like manner, the multiplication by the discount factor is saved in the final value calculations. A still further saving of time would be realized by adding the discounted costs as of each date of prediction for successive total-number of years, and obtaining the total discounted cost of operating for any number of years. In the final value calculation by this procedure, subtracting the cost of operating needs to be done only once instead of separately for each year. The tables suggested in this paragraph are unnecessary if a uniform cost of operating is given in M. cu. ft. instead of changing by years.

Cost of Operating in a New Enterprise.—The discussion so far, has been on the assumption that the company has been in operation long enough to secure necessary cost data. With a contemplated enterprise one can follow either of two procedures for basing the cost estimates:

(1) By comparison with like ventures.

(2) By detailed analysis similar to that made by engineers when planning construction costs.

In the first case the appraisor should exercise care to have as close a similarity as possible in all conditions under which each is operating. If variations exist, adjustments in accordance with the findings are essential. In almost every appraisal some such estimates are required, but can generally be easily provided for by facts available in the company files.

Where no precedent has been established or is obtainable, the complexity and inaccuracy of the prediction increases. An analysis of probable cost involves an estimation of labor, repair material, royalties, rentals, taxes, superintendence, general overhead and contingencies. The amounts and especially the costs of each are difficult to determine for many years in advance and for this reason the trend of prices in each must be found from some source. Greater efficiency and lower unit operating costs can be expected as the plant expands, or if there is no change in prices, with the increasing experience.

A merger or consolidation often results in lower general operating costs. A company with several subsidiaries, each working as an entity, may, through a merger eliminate a certain amount of duplication and thus lower the costs. The wages saved will be the greatest advantage but it also may make it possible to eliminate certain equipment.

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Chapter XII

FUTURE COST OF DEVELOPMENT AND IMPROVEMENTS

Oil or Gas

PURPOSE of Future Development and Improvement Costs.—In predicting revenue from undeveloped properties, unconstructed gasoline plants, compression stations or pipe lines, one should deduct the amount of investment anticipated from the predicted earnings. The gas on an undrilled property cannot be recovered without an expenditure for drilling, rigs, casing, tubing and other equipment. Obviously, some provision is necessary for this investment.

Prediction of Cost of Future Investments.—The prediction for each class of equipment will have to be carried out separately. Two procedures can be followed:

1.—Prediction of cost on an engineering estimate such as contractors present when bidding for construction work.

2.—Total cost predicted on the past experience of the company in the construction of similar plants, lines or development projects.

In the first case lack of data as to past experience on the property or analogous properties, makes necessary a detailed estimate by units, especially in the oil business.

If the work is being done in this country in an untested region naturally data are lacking. Until the cost per foot to drill, the amount and size of casing and tubing required, together with the transportation expenses on the same are known, the cost of the first well is more or less uncertain. As regards making extensions, the attitude of the beds, especially in regions of steep dip, must be considered, as there is likely to be considerable variation from the cost of the first well, as in Salt Creek, Wyoming.

Transportation costs are variable as rocky, swampy or sandy country makes the hauling more difficult. Many places in Utah, Montana and other Western states are at prohibitive distances from railroad. Aside from the usual teaming or trucking costs there may be unlooked for trouble in fording or ferrying.

An incident in Kentucky is recalled where it cost nearly four hundred dollars to take a #2 Star machine across a small stream. The only available crossings were held by licensed ferrymen who owned a small strip of land on either side of the landing places. In addition to an exhorbitant ferry charge —for the flat boats could easily handle the rig—a so-called dockage charge was made, which was nothing more than a charge for having used the strip of land in the course of loading and unloading.

Labor costs are uncertain. In a region being newly developed the wages may be unduly excessive until labor becomes plentiful. In a foreign country, disease, necessity of importing skilled labor, distance from supply centers, climatic conditions, housing difficulties, high labor turnover and many unforeseen contingencies make the expenses very high. In fact, exploration work in foreign countries can only be successfully carried on by large companies capable of financing the project. A small tract is, therefore, ordinarily valueless except to sell to such a purchaser.

The method mentioned under case two above can generally be used and is simpler. Assume that fifteen wells are to be drilled each year for three years. Ten of the wells are scattered "wildcats" and five on a partly developed property. The future cost of the ten "wildcat" wells can be based on the average past cost of all wells drilled under like conditions. Cost of all wells drilled in the past need not be secured but a sufficient number should be chosen to give a representative average. Having found the average cost per well for several years, one can make prediction on the basis of this information. For the five wells on the partly developed tract, the cost of development of the wells already on the property and adjoining properties will furnish a satisfactory foundation for predictions, if like conditions prevail.

If investment is planned for a year hence then, as a rule, the average cost for similar installation or development for the current year will be sufficiently accurate, unless one sees a change in costs is likely to occur before that time.

Pipe line or other building costs can be postulated by comparison with previous expenditures for a like venture. Either a table or a chart can be devised to facilitate the computations. Of course all items cannot be covered by either a table or a chart because of its inapplicability to any region having peculiarities.

Where past costs for similar projects are not available, a detailed analysis of probable expenditures is essential. This requires plans, detailed lists of all equipment and a list of probable labor, superintendence, cartage, storage and contingent costs.

Determination of the Amount of Deferment.—Where the rate of future development on undrilled areas is desired, a study of both field conditions and of company policy should be made. An analysis of conditions in the field is important to determine which leases need immediate development and where the offsets should be drilled. The company policy determines the number of wells or the amount of investment the officials will approve of. Additional pipe lines, compressing stations, powers, gasoline plants and other installation are generally contemplated some time in advance and the date of completion can be tentatively decided upon. The time when a pumping plant will be required for wells in a gas pool should be determined for wells not yet on the pump.

Deferment for undrilled wells cannot be predicted very far into the future. The hazard increases with the delay, to a time when the risk cuts down expected receipts below expected costs. In producing areas, delay greatly reduces the value of a property by loss of gas pressure, which greatly decreases both initial and total production. The discount to be applied on delayed investments and the expected returns therefrom often decreases the present worth to an insignificant amount.

Method of Entering Deferred Investment Into Computations.—Various methods for deducting deferred investment from the deferred earnings are in use. The simplest happens to be the most accurate, namely, to find the present value of the future net revenue to be derived as a result of the particular investment; then find the discounted or present value of the investment required and subtract from the present worth of receipts. This automatically distributes return of capital over the future life. Some engineers and company officials prefer to have the investment returned first and the balance considered profit. Following are examples by both methods:

(1)—Investment to be subtracted from total net earnings, no discount applied.

Year	Net Profit
1	$10,000
2	9,000
3	8,000
4	7,000
5	6,000
Total	40,000
Less Investment	$20,000
Profit	20,000

(2)—Investment to be returned first. No discount applied:

Year	Net Reserve	Net Profit	Am't Investment remaining
1	$10,000	....	$20,000
2	9,000	....	10,000
3	8,000	$ 7,000	1,000
4	7,000	7,000	....
5	6,000	6,000	....
Total	$40,000	$20,000	....

It is obvious that when discounted, the present worth by the first method is less than by the second method.

The second method can only be fairly used when the investment must be returned at once, which is only likely where money is borrowed and an immediate return is essential. The first method is the commoner procedure to apply in appraising most oil or gas properties.

General Investments.—Investments to be made which are common to the whole organization and not directly attributable to any particular income-making source can best be handled with reference to total present worth of all future earnings. Telephone lines, general offices and warehouses come under this class of investment. When an individual property valuation is being made a share of such probable general investment items should be accounted for.

Cost Drilling Wells—Outline.—Because of the rapid fluctuation of drilling and equipment costs, it has been deemed advisable to submit an outline only, rather than detailed information. The factors affecting costs are primarily (a) proximity to supply houses, (b) labor, (c) number drilling contractors available for demand, (d) nature of formation, (e) strings of casing necessary, (f) fuel and water supply, and many other variables. The following outline indicates the items to be considered in drilling:

If the well is producing there will be additional expenditures for tubing, pumping equipment, sucker rods, rod lines, power, flow and stock tanks, gathering lines, lease houses, warehouses, etc.

Rig	Costs
Type................Size rig irons	....
Drilling	
................feet at................per foot.................	
................feet at................per foot.................	
................days underreaming at..................	
................days shut down at....................	....
Freight and Hauling	
Casing, tanks, flow lines, etc....................	....
Fuel and Water	
................days gas at..................	
Water service	....
Casing	
................feet of................inch..................pound casing	
................feet of................inch..................pound casing	
................feet of................inch..................pound casing	
................feet of................inch..................pound casing	....
203-c	
Shooting	
................qts. shot of nitroglycerin..................	....
................days cleaning out at......................	....
Contingencies	
Add at least 100 per cent for unforeseen expenses	
Grand Total	....
Less probable salvage for producing well	....
Net cost of producing well	....
Less additional salvage if dry hole	....
Net cost of dry hole	....

If the well is producing there will be additional expenditures for tubing, pumping equipment, sucker rods, rod lines, power, flow and stock tanks, gathering lines, lease houses, warehouses, etc.

Appraisal Of Oil And Gas Properties

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CHAPTER XIII

THE DISCOUNT FACTOR IN ANNUAL ANALYTICAL APPRAISALS

Oil or Gas

EXPLANATION of the Meaning of Discount.—Let us suppose that with the purchase of a property the vendee obtains a certain amount of oil or gas in the ground, with perhaps the equipment necessary to remove the product from its reservoir. This reserve represents future earnings. In mines it is often possible, by the construction of a plant with sufficient capacity, to remove in one year all the recoverable mineral. This is hardly possible in most oil or gas fields, since the rate of production at the wells is controlled by pressure on the fluid and by its rate of migration. These future earnings will, therefore, be distributed over a period of years. Each dollar invested now, and retained in the earth as units of oil or gas, has its value reduced in proportion to the number of years before the product is brought to sale. This diminishing value is due to the inactivity of the money invested, inasmuch as it cannot be placed in securities or other interest-bearing investments until oil or gas is recovered and has been exchanged into cash or its equivalent. Therefore, receipts to be taken from the property at some future time, must be discounted by compound interest for the period of time withheld, in order to obtain that amount, which, if compounded annually, would be equivalent to the deferred payment or payments.

Other Industries Using Analytical Appraisals.—It is strange that of all the natural resource industries, the oil and gas industry alone has not fully recognized the necessity for valuation by method of present value. This method has been used for many years for all kinds of mines and is very ably discussed for the mining and allied industries by Hoover, in "Principles of Mining"; Finlay, in "Cost of Mining"; Herzig, in "Mine Sampling and Valuing"; and for forests by Chapman, in "Forest Valuation." It is used advantageously in the timber industry under the conditions peculiar to it alone.

The reasons for this delayed use lie in the rapid rise of the petroleum and natural gas industry, and the comparatively rapid return of the investment. With the progress made in recent years in estimating future reserves, the use of analytical appraisals is becoming more common.

Like the solid minerals, oil and gas are wasting assets; that is, every unit of gas removed diminishes the ultimate amount to be recovered. This is depletion. Depletion plus depreciation throughout the life of the well should equal the total final redemption fund. The factors relevant to the determination of these installments to the fund will be fully discussed under another caption. A difference must be recognized between true profit, for, with the depletion of the resource, a portion of the apparent profit must be set aside as the return of the capital investment as well as other capital allowances. Thus the gross yearly income should be divided into risk insurance, interest profit and the redemption of capital. The risk insurance, interest and profit are the yield or return and the redemption is the amount which must be set aside so that when all of the oil or gas has been extracted the amount originally invested has been returned.

Following the determination of the net earnings or deferred receipts anticipated, it becomes necessary to reduce these to their present value.

Rate of Discount.—The discount factor adopted should include (a) a reasonable rate of interest and (b) a reasonable margin of profit.[1]

The rate of interest is that which the money could return, if it had been placed in the securities or stocks of a thoroughly reliable organization. In general, the rate of interest is from six to eight per cent. Few operators will invest money if the return expected is no greater than the interest on securities. The peculiar nature of the oil or gas business requires a reasonable profit, for there is always a large overhead expense to carry on undeveloped and reserve tracts, even when risk has been previously provided for. Whether these tracts will be operated later or surrendered depends upon the results of tests

[1]Risk is considered under a separate heading.

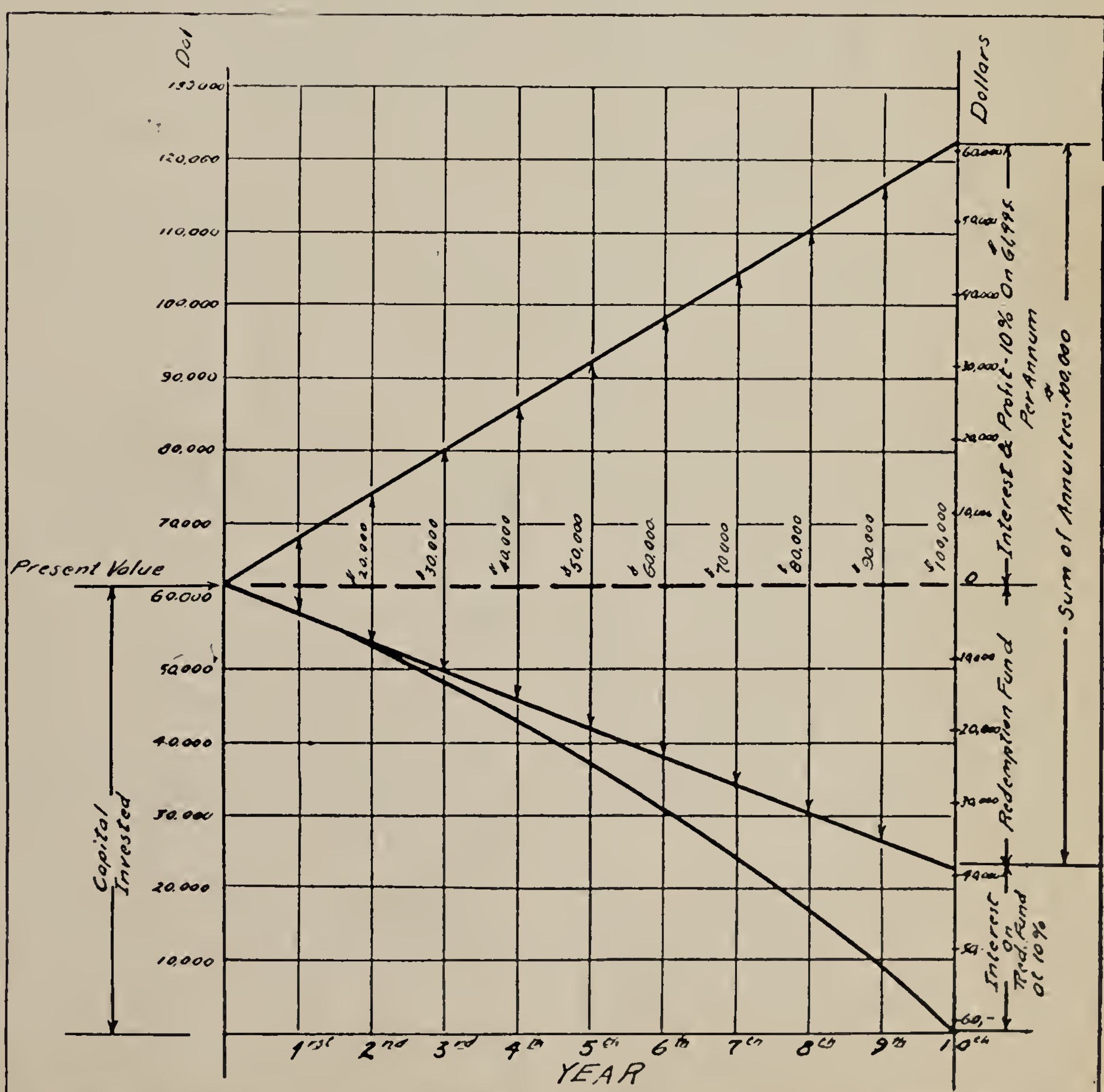

Figure 30.—Diagram illustrating the distribution of returned annuities. Uniform annuity of $10,000 per annum assumed an redemption compounded at 10% per annum.

in the vicinity. The burden of the cost of these surrendered leases must be balanced by the profit on producing tract. No company can maintain its size if it is not continually acquiring new tracts in regions that are producing or being explored.

To illustrate graphically what is redemption fund and discount factor the diagram, Fig. 30, has been drawn. In the computation of data for this diagram, uniform annuities of $10,000 for ten years have been assumed and have been discounted at 10 per cent giving the present value of $61,455. Redemption of capital is at 10 per cent compounded annually. This allows a six per cent interest on the investment annually and four per cent additional as profit. Risk has not been considered in order to simplify the problem. In the diagram below there is shown the broken line, for each year the capital invested and returned to date, plus the interest thereon. The amount above the line is the interest plus profit returned to date. It might be well to note that the capital returned on the investment at any given period is not a direct proportion of the life of the property already expended to the total life. For example, at the five-year period the redemption plus the interest thereon is $23,445, one-half of the reserves have been returned while the redemption fund is only about 38 per cent of the capital originally invested instead of 50 per cent as would be expected. However, the percentage increases with the compounding of the interest, until at the expiration of the period, the redemption fund is 100 per cent of the capital invested.

The portion of the discount, then, in excess of the interest rate, is dependent upon the profit which the company computes as necessary to maintain an organization according to the plans outlined by its officials. Thus the profit factor is determinable only by the executive staff, as they realize what the net income must be in order to continue their corporate existence. In the case of those natural gas companies that serve as public utilities, the percentage of interest or return on the investment that is permitted to gas companies by the Public Utilities Commission fixes the discount rate. However, in their case a valuation is allowed on undeveloped acreage and other deferred income making parts of the company. In consequence, the actual rate of profit on the investment in the producing portion is greater than the percentage of interest permitted on the whole.

Profit on investments is not determined wholly by the policy of the company. There is a variable established according to (a) locality, (b) size of tract, (c) stage of development, and (d) age of production, as a company frequently anticipates different profits under these different conditions. Many companies will not purchase a property with small production and correspondingly small margin of profit, while others desire only such properties. A rate of profit above interest and fixed by these elements must be anticipated before the investment appeals to the purchaser. It is important that this profit rate be calculated from the elements listed. Once the interest and per cent of profit has been established, the next step in obtaining the present value of deferred receipts is to discount these receipts, which represents the combination of the two per cents, by the discount factor. The resultant present value is the amount that, if paid in the purchase of a property, will eventually return the capital invested and the interest plus the required profit.

Interest in Relation to the Size of the Company and the Locality of the Holdings.—It is probable that were an analysis made of the profits realized on investments the companies would arrange themselves in various groupings as follows:

1.—Small companies.

(a) By regional distribution of properties; whether in the Mid-Continent, elsewhere, or in more than one locality.

(b) By varying degrees of aggressiveness of officials; whether expanding or operating on present holdings.

Companies of average size.

(a) As above.

(b) As above.

(c) As in (a) except that some possessions may be in foreign countries.

(d) Refineries and pipe lines in connection with production.

3.—Large companies.

(a) As in 1 (a).

(b) As in 1 (a).

(c) As in 2 (c).

(d) As in 2 (d) except that the large companies usually own their pipe lines and refineries which are more extensive and of greater capacity than those of lesser companies.

The discount rate should be more than a mere guess and a normal rate should be found for each company. This normal rate will serve as a basis of the discount factor for properties being valued. It is evident that a large company operating a refinery can frequently better forego all profit from its producing division and take even a small refinery profit rather than allow the refinery to rest idle. Smaller companies never have this leeway.

Methods for the Redemption of Capital.—Closely allied with the discount rates to be used are the various methods for the redemption of capital. In the choice of a discount table the engineer will primarily consider the disposition of his redemption fund. The formulae by which present values are determined are fully discussed by Hoskold.[2]

For the purpose of illustration, it is being assumed that an oil or gas company is making gross earnings of a certain sum annually. Three problems occur.

(1) Assuming a reasonable rate of interest on the investment, in how many years will the capital be repaid?

(2) Assuming a certain number of years as the profitable life of the property and a certain rate of interest, what sum must be paid each year to repay the capital in the number of years assumed?

(3) Assuming the number of years in the profitable life of the property, and the sum paid each year, what interest is being yielded on the capital invested?

The eventual return of capital is dependent upon the method of its disposal as it is being returned to the company. The interest received is directly related to the method of disposition of the redemption fund (sinking fund).

The three methods for determining the amount necessary for the redemption fund are:

(1) When the capital returned is improved by compound interest annually at the same rate as the interest and profit desired on the investment.

(2) When the capital returned is improved by compound interest annually at a rate differing from that desired on the investment.

(3) When the capital returned is not improved by interest.

Case (1) is the most commonly practised. A large oil or gas producing company generally uses the redemption fund for purchasing of other properties of like nature. Thus the ultimate result is an average interest and profit being earned on investments and redemption fund alike. In other words, the redemption fund loses its identity in investments similar to that in which it is being returned.

In case (2) the company is not expanding the business and therefore places the redemption fund into securities which promise a certain interest, usually less than the interest being returned from the initial investment.

In case (3) it is assumed that, for reasons unknown, the company is holding the redemption fund in its own treasury and therefore is not improving it by interest.

The Discount Factor for Oil and Gas Companies.—All published tables of discount factors are based on the assumption that the average time of return of revenue is as of the end of each year. Oil companies as a rule have a pipe line run at least once a month, while gas companies generally collect bills for sale of the product at similar periods. Obviously, an error is introduced in the computations if the discount factor does not provide for this difference.

Computation of Discount Factor.—The formula for finding the value of $1.00 due in N years may be stated as follows:

$$V = \frac{1}{(1 + r)^n}$$

In which V = deferred value.
r = rate of interest.
n = years deferred.

[2] Hoskold, H. D., Engineer's Valuing Assistant. pp. 1-28.

To simplify the calculations the formula can be taken as:

$$V = \frac{1}{R}$$

In which R is $1 improved by interest to the nth year. Thus the present value of $1 is the reciprocal of that amount improved by compound interest for the same period.

Example.—Find the present value of $1 due in 10 years at 12 per cent interest.

Solution.—From the interest table it is found that $1.00 compounded at 12 per cent for 10 years is $3.1058. Thus:

$$\frac{1}{3.1058} = .32197$$

The present value of a larger amount at the same rate and time of deferment would be 0.32197 × the amount.

In the oil and gas industries, however, the interest on capital receipts is returned at intervals during the year, most commonly each month, instead of one single payment at the end of the year as most discount tables assume.

Here is the most practical equation for solving a discount factor with provision for this frequent return:

$$\left(1 - \frac{r}{m}\right) m\ n$$

In which m = number of times during the year interest or receipts are to be realized.

n = number of years deferred.

r = rate of interest.

Assuming the investment to be $1 and the rate 6 per cent per year, for payments twice a year the solution is:

$$\left(1 - \frac{.06}{2}\right)^2 = \$1.0609.$$

And for four times a year the solution is:—

$$\left(1 - \frac{.06}{4}\right)^4 = \$1.06136.$$

And for twelve times a year it is:—

$$\left(1 - \frac{.06}{12}\right)^{12} = \$1.06167.$$

A still simpler form is to consider the yearly revenue as all being returned as of the middle of each year. Thus for the first year, the formula originally stated, reads:

$$D = \left(\frac{v}{r}\right)^{n\frac{1}{2}}$$

For the first year by substitution we have:

$$1.04880 = \frac{0.95347}{0.10} \text{ which was } D = \frac{1\frac{1}{2}}{0.10}$$

assuming v = $1 and rate 10%.

Following are three discount tables for 10 per cent arranged for comparative purposes; the one being made from monthly increments for the first year (with one-half of the increased yearly rate used for half the year) while in the second table the yearly annuities are all assumed to be returned as of the middle of the year, and in the third as of the end of each year:

DISCOUNT AT 10%

Year	By monthly increments	By all receipts as of middle of year	As of end of each year
1	.95346	.95347	.90709
2	.86678	.88685	.82644
3	.78798	.78802	.75131
4	.71635	.71644	.68501
5	.65123	.65138	.62092
6	.59202	.59207	.56447
7	.53820	.53821	.51313
8	.48927	.48948	.46650
9	.44479	.44484	.42409
10	.40435	.40437	.38554
11	.36759	.36751	.35049
12	.33418	.33784	.31863
13	.30380	.30395	.28966
14	.27618	.27624	.26333
15	.25107	.25113	.23939

It is to be noted that the difference is all in the fourth decimal place in the first ten cases of the first two columns, which is immaterial when risk factors frequently do not even go into the third place and reserves can often be estimated no closer than ten per cent. Consequently in computing a table the procedure used to obtain results in the second column is sufficiently accurate and easier. The factors in the third column are not in accordance with the way either oil or gas payments are received.

Present Value of $1 per Annum in N number of Years.—A formula can be expressed for the method of finding the value of $1 per annum for any number of years. Inasmuch as discount tables are required, the mathematical procedure will not be given, but a method based on the tables will be used. If for instance, a factor of present value of $1 per annum for ten years is desired, it can be obtained from the discount table devised, by adding all discount factors for the first ten years. It is best to make up a complete table. The desirability of such a table is evident when making computations to determine the total discounted amount of operating cost chargeable to an appraisal when the operating costs are uniform from year to year.

Delayed Initial Revenue.—Not infrequently receipts expected from undrilled locations, on unconstructed gasoline plants or other sources, are to be valued, where the commencement of the return of revenue is necessarily postponed by time of development, marketing or transportation difficulties. The discount factors applying to deferred annuities in general are not applicable in these cases. For example, suppose the first earnings are to commence in three years. Since in the oil and gas industries, annuities are not returned at a uniform rate, each year will have to be dealt with independently. Suppose for exmple, however, that the annuity is to be $10,000 per annum for the seven years of the probable life of the property in question. By reducing the first annuity by the 10' per cent discount factor applying to an annnity due in three years, the second in four, etc., it is found that the present value of these seven annuities is $44,087. Ten per cent or $4,408 per annum is desired as interest and profit which leaves $5,592 as the amount attributable annually to the redemption fund. This amount compounded by 10 per cent interest for seven years equals $53,000. Now for the first two years neither interest nor profit was realized. The difference between $53,000 and $44,087, the present value, is $8,913 or the 10 per cent for the two cent or years of deferment.

Reduction of Final Value for the Delayed Return of the Initial Revenue by a Fixed Percentage.—In order to make restitution for loss in value incidental to delay in begining of return of earnings, a table of correction percentages was found to be reasonably accurate and is useful when time for the work is limited. The present value of wells of various sizes in a pool is found and likewise the value for the same wells when deferment is assumed. The computations for one pool are as follows:

Discounted Net Value—No deferment	$1,646.33
" " " Deferred 1 year	1,639.30
Difference	$ 7.03
Per cent of difference	0.45

Large and small wells show a difference in percentage of deduction, for example:

	Wells Above 150# C. P.	Wells Below 150# C. P.
Harrison Co., Sardis Dist. W. Va	3.2%	0.45%
Harrison Co., Union Dist. W. Va	3.25%	0.25%

By the adoption of such fixed percentages for several years of deferment, considerable work is saved. A location off-setting a producing well can be given the value of the producing well and then adjusted by percentages for risk, deferment and production difference, eliminating much calculation.

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Chapter XIV

INVESTMENT RISK

Oil or Gas

EXPLANATION of Risk.—The element of risk is involved in the purchase of nearly every oil and gas property whether producing or non-producing. The amount of risk is controlled by the many varying conditions found in the industry. The greater the hazard the more speculative the investment becomes, but the more readily this hazard can be measured, the sounder becomes the investment. It devolves upon every valuation engineer to determine as closely as possible what the risk is and what is the probable error of the results. Of course, with the increase of speculative elements in the valuation, the refinement of the calculation decreases.

Methods of Making Allowances.—In making provisions for risk in valuations, three methods have been employed:

1. Liberal reductions throughout computations.
2. Final reduction of valuation by multiplying by a risk factor.
3. By increasing the discount factor being used.

Objections or Advantages of Methods

Method 1. Risk should be considered in the aggregate. If liberal separate reductions have been made throughout the computations the real total amount taken is hidden and may easily be excessive.

Method 2. Risk is provided for by one reduction, namely, that of the final valuation. The deduction should be made by a percentage allowance, as the final valuation is present worth, and a reduction by monetary amount would be incorrect, unless such an amount is the present value of risk allowances.

Method 3. Risk is something which should be compounded annually over the life of the property. The actual per cent of risk thus realized is not determinable until the redemption fund, interest and profit have been segregated from the annuities. Further, if risk is added to the discount factor, the capital returned, (or the redemption fund), will be improved by compound interest annually at the total discount rate used, whereas the interest on the redemption fund would probably be at a different rate.

Factors Determining Well Development Risk.—The fundamental factors in the consideration of risk fall under groups according to the location, nature, status and size of the property, as:

1. Where the property is a long distance from any other development and is only partly developed.
2. Where the property is adjacent to or surrounded by development and is itself undeveloped.
3. Where the property is adjacent to or surrounded by development and is wholly or partly developed.

The speculative element decreases from situation (1) to situation (3), where it is at a minimum.

Of paramount importance in the determination of the allowance for risk are the geological, economic and administrative elements as follows:

A. Geological and historical—
   1. Structural.
      a. Kind and size of structure.
      b. Location of tract thereon.
      c. Structural conditions that are most and least productive in the locality.
      d. Nature of unconformitive above producing sand, if any.
   2. Sands.
      a. Number.
      b. Lenticular or continuous.
      c. Even in texture or irregular.
      d. Porosity.
      e. Thickness.
      f. Depth.
      g. Water.
         1. Water in the producing portion or only in certain areas of the pool.
         2. Reservoir free from water.
   3. Metamorphism.
      a. Fixed carbon ratio of coals.
      b. Other evidences of metamorphism.
      c. Relation of geologic age of (a) to that of producing horizon.
   4. Historical.
      a. Number and history of wells nearby.
         1. Dry holes.
         2. Abandoned wells.
            a. Initial production.
            b. Ultimate production.
         3. Producing wells.
            a. Initial production.
            b. Rate of decline.
            c. Amount of water.
            d. Ultimate production.
            e. Encroachment of water.
            f. Other data.
      b. Amount of developed acreage on the tract.

B. Economic.
   1. Market Conditions.
      a. Decrease in price.
      b. Decrease in demand.
   2. Physical Condition of Equipment.
      a. State of casing and property not visible.
      b. State of visible property.
      c. State of repair.
      d. Care given equipment by management.
   3. Fluctuation in the cost of operating and development.
      a. Lack of labor.
      b. Changing cost of equipment and maintenance repairs.
      c. Error in estimating costs.
      d. Unforseen loss at hole.
   4. Taxes.
      a. Change in local and federal tax rate.
   5. Hidden Liabilities and Title.
      a. Liens.
      b. Unknown mortgages.
      c. Defects of title.
      d. Legislation making title defective.
   6. Contingencies.
      a. Transportation.
      b. Character of competitors.
      c. Governmental regulation on ownership.
      d. Fire, tornado or other fortuitous accidents.

C. Administrative.
   1. Efficiency, integrity and honesty of executives.
   2. Assumption that the plan and scope of the work will not be altered.

Careful weighing of all these items will result in a factor which is considered sufficient to compensate in the valuation for the hazard of the venture. The geological factor will, to some extent, follow the theory of probabilities, namely:

1. The probability that, among several equally possible events, a given event will happen, is ratio of the num-

ber of favorable cases to the whole number of possible cases.

2. If the probability that an event will happen is p - , the probability that it will fail is 1 - p.

3. The total probability of an event is equal to the sum of its partial probabilities.

4. The compound probability of two independent events is the product of the probabilities of the two events taken singly.

5. The mathematical expectation is the product of a sum of money, the payment of which depends upon the happening of some event, multiplied by the probability that the event will happen. If $6,000 is offered if one dice comes up three, the mathematical expectation is $1000; if $6000 is offered that the sum of the points coming up on two dice is seven, the mathematical expectation is 6 in 36 or $1000.

Hence, if the net profit expected for one producing well is $100,000, and the chance of getting a well and not a dry hole is 1 in 4, the mathematical expectation is $25,000.

For the economic and administrative portion, business acumen must be the guide in any particular case for the determination of this part of the total risk per cent.

Risk Versus Time.—It goes without saying that risk becomes less toward the end of the life of a producing property, that is, the greater the percentage of capital returned, the less is the amount still at stake. Some companies consider that all the income until the total capital has been returned is return of capital, and the remainder will be profit. This would not require a proportionate annual return of capital but would defer dividends until after the capital had been returned.[1] In a company that is primarily a "wildcatting" company, much is to be said for such an arrangement, but it is not permitted by the Income Tax Regulations and has now been abandoned accordingly.

Risk Versus Size of Company.[2]—"A very large company undergoing many risks would consider this element as nearly negligible; whereas the individual operator of small capital ought to put it quite high. Nevertheless, in any isolated valuation for a big company the risk factor is of prominence equal to that for the small company on the same property. The large company, however, could chance a smaller reduction for risk than the lessor one because of the greater distribution and size of its assets."

Reduction for Risk from Final Valuation.—Upon thorough analysis of the many methods of accounting for risk, it is apparent that the most direct, simplest, and most expedient method is to reduce the final present value by a certain percentage determined for risk. The best from a standpoint of redemption of capital calculations is to reduce the net earnings anticipated for each year by the risk percentage. Either method results in the same answer, and the former procedure requires only one operation.

Determination of Dry Hole Risk.—The dry hole risk in computation depends almost entirely upon the location of the wells for which the factor of risk is desired. If the locations are offsets, then all dry holes that were offsets to producing wells are used to figure the risk. The percentage of these in the total number of such wells completed in the pool establishes the average risk of dry holes for offset locations. This average figure can be altered when applied to any location, if it is felt that, because of its geological position on the structure or for other qualifying reasons, the chances are better or worse than for an average location. The "wild cat" risk, that is, the risk in locations distant from producing territory, is also determined as a ratio of failures to the total number of attempts for locations of this type in the region.

When dealing with a large company, where time for an appraisal of considerable refinement is impracticable a general risk factor, made up of the ratio of all dry holes to all holes completed for the company as of each year, and for the total to each year, will suffice. From these data find the percentage of risk for each year and the average percentage for the history of the company to each year. If more information is available from another source, compute a factor of risk for the pool instead of for the company. The yearly risk factors when plotted on graph paper reveal any annual change in the amount of hazard. (See Fig. 31.) In making appraisals of undrilled locations deferred for any considerable time, a postulation of future risk is more accurate than simply applying the average past risk. In general an average risk factor, if applied indiscriminately, should be based on a variety of locations at various distances from production. Whenever possible, a narrower scope of risk factors should be sought. Risk is generally too lightly considered and dealt with arbitrarily, while utmost refinement is employed in some other step of the calculations. Such evasion is carelessness or failure to recognize the relative importance of this element of risk.

Risk of Abandonment.—So called risk of abandonment means the probability of a producing well not yielding the amount anticipated for an average well. Such a risk factor is not pertinent when every producing well is used in the construction of the decline curves and many wells are being appraised. Often smaller wells, or wells that were suddenly abandoned because of water or other trouble or because they were erratic, are omitted from the curve calculation. Thus, a curve results comprising wells of better than average production. In such cases to offset the danger of erroneously high valuations, the risk of abandonment ought to be taken into consideration. Any calculation for this risk is more or less arbitrary but is better than a mere guess. The following table of computations for a certain West Virginia pool will be presented first and an explanation later:

	As of 1912	As of 1913	As of 1914	As of 1915	As of 1916
1—Total number of producing wells completed to date	90	93	97	101	102
2—Number of wells abandoned to date	4	8	18	21	24
3—Average total production per well abandoned (bbls.)	16,000	17,000	19,000	20,000	22,000
4—Estimate of average ultimate production for wells producing (bbls.)	42,400	40,800	30,000	36,000	34,200
5—Percentage of 3 to 4	38	42	50	56	64
6—Well equivalent of oil produced by all wells abandoned. (In units of wells.)	1.5	3.3	9.0	11.7	15.4
7—Equivalent of the number of wells abandoned having no production (2-6)	2.5	4.7	9.0	9.3	8.6
8—Percentage of risk of abandonment (7-1)	3	5	9	9	8

Computations of Above

1. All the wells completed as producers in the field as of the end of each year.

2. Total number of wells abandoned to the end of each year.

3. From company records the average total production per well from those abandoned.

4. Estimate of average ultimate production per well as of each year. This is obtained by finding the average recoverable reserves remaining for the producing wells and adding thereto the amount produced in the past. A quicker way would be to find the average initial production in the case of oil; or for gas, either open flow, closed pressure or minute pressure for all wells, and from the composite decline curve for the pool, estimating the probable ultimate yield. The latter process is less accurate.

5. Percentage of the production recovered from the average well abandoned in relation to the average ultimate production of all wells.

6. The percentage in (5) is multiplied by wells abandoned in (2) to obtain the average well equivalent of this production.

7. By subtraction of well equivalents in (6) from total number abandoned in (2) an estimate of the number of wells that are equivalent to dry holes is found.

8. The number of wells considered as dry holes in (7) is divided by the total number of producers in (1). This is the percentage sought for.

It is recognized that there are a few minor fallacies in the procedure, most

[1]E. C. Graton—Federal Taxation of Mines—Bull., 155, A.I.M.E. 1919. Reference to a similar problem worked out by Dr. J. C. Hance shows that the allowance for risk on this basis is greater than the percentage properly assignable to risk.

[2]R. H. Johnson and L. C. Huntley—Principles of Oil and Gas Production, 1916, p. 235.

important of which is the possibility of including wells abandoned which have had a normal or better than normal life and were abandoned because of age.

This risk factor can be used in connection with the valuation of new wells. As wells become older the risk decreases, in fact if the decline curve indicates a return of fifty percent of the production in one year, the risk is cut in half the second year of the life of the well. For undrilled wells there is the added risk of getting a dry hole.

General Risk.—The company is justified in demanding remuneration for risk on other than the geological and production factors so far allowed for. General risk may be regarded as the factor indirectly affecting appraisals. An outline has been given in which such various economical and administrative risks are shown. No definite method is proposed for computing the hazard under these headings. The investigator will have to be guided by general and qualitative considerations in fixing a suitable percentage.

Accessibility of Reserves.—The distance from transportation lines and a rough topography often delay progress in drilling or construction. Although the expense incident to delay and difficulties can be calculated, many unforeseen inconveniences and expenses are possible in regions of difficult access. Railroad projects may make exploration possible in a region where the cost would otherwise have been prohibitive. Thus mere potential value is changed to a higher potential value and later to a tangible value.

Title of Tract.—Where the title to any leases or other property is not clear, the probable outcome of litigation should be considered. Where contracts have been given for construction or other work all receipts should be checked to avoid filing of liens. There are many cases of leases with doubtful title. Development ought to be suspended in general until a quit claim deed can be obtained from the claimant or a strong legal opinion on the invalidity of their claim be secured. Frequently by legislation or court decision what has hitherto not been considered a defect now becomes one. Owing to the fact that the disputant generally delays making an appearance until the value of the lease has been enhanced sufficiently to make a law suit worth while, it is difficult to express this risk as a percentage, yet such an attempt should be made. One case is known in Oklahoma where the day following the completion of an important discovery well, over twenty applications were made for abstracts of the lease title. Deviously, each of these persons was searching for a cause of legal action against the fortunate owner.

Character of Competitors.—At the distributing point of gas there are frequently several companies with franchises. This is especially true of companies in the larger cities, as for instance in Pittsburgh, Pa., with three large distributing companies and numerous smaller ones in the outlying boroughs and suburbs. Although there is apparently only the closest co-operation and harmony between them, an appraiser for any one must consider the possibility of occasional friction and a consequent miscarriage of plans. The point is emphasized where a large industrial consumer alternates from one company to another to satisfy certain suppose grievances. There can be honest competition and co-operation, but one must always allow for a change of officials, and incidentally a change of policies.

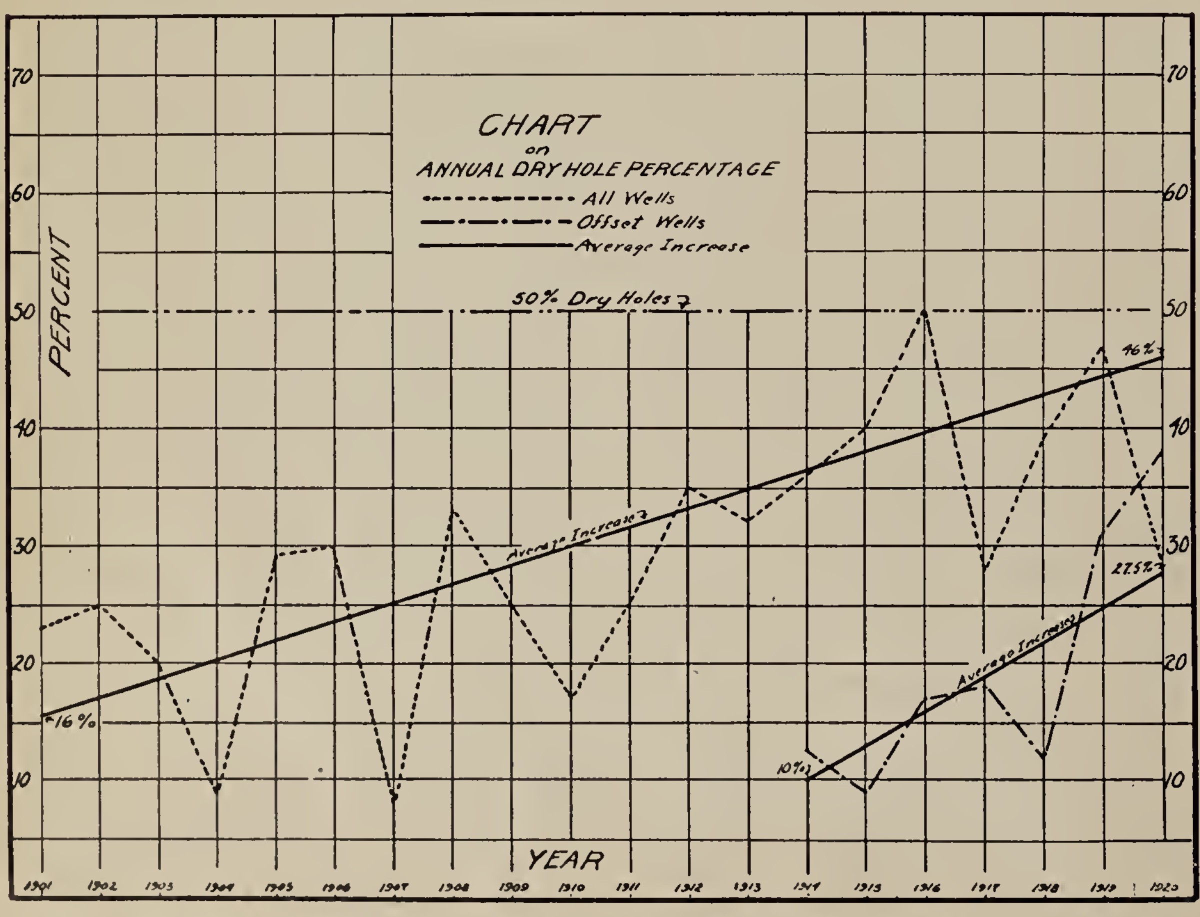

Figure 31.—The increase in percentage of dry holes for one company.. The average increase of all wells if drawn in a curve would show a tendency to flatten in the last few years

Physical Conditions that Affect Cost.—The difficulty of obtaining and retaining labor in remote regions is probably the most important. Unexpected labor troubles often arise from trivial disputes or dissatisfaction over living conditions. The cost of construction may increase enormously because of a large labor turnover, with its coincident loss of time and disruption of organization. The failure of the management to provide suitable quarters and living conditions often impairs the morale of the men and results in inefficient work. In addition, early frost, a long, cold winter, an excessive wet spring, or summer draught may menace field operations. Abnormal weather conditions, as a rule, increase the cost of development. Such contingencies need to be provided for in any estimate of future costs.

The equipment on a property may be in a poorer condition than is ascertainable by examination. This is especially true of casing and other material hidden from view. Cases have been known where bearing surfaces and other parts of engines were packed with cork to eliminate all vibration and to appear to be in first class condition. This of course, is unusual but demonstrates one of the practices likely to prove disastrous to the purchaser of the property.

Management.—After making plans for future construction and development work and basing the valuation on such plans, provision must be made for the failure of the management to adhere to them. Well locations drilled in places other than originally outlined may demand much greater reductions for risk than has been allowed for. Construction of a gasoline plant may be deferred for several years longer than was estimated. It is necessary that allowanc be made for a possible altering of the program. Field superintendents or other men in authority may not carry on the work as efficiently as has been the former policy. On the other hand, it may be carried out more efficiently. In an appraisal it is seldom wise to assume that costs will be cut down. To accomplish this is far more difficult than might be supposed.

Contingencies.—All factors indirectly affecting valuations can be classed in one group and termed "contingencies." For these a lump adjustment by a certain percentage must be made to the final results. The percentage can only be fixed after a thorough study of the possibilities has been analyzed and then only more or less arbitrarily. Investment risk decreases value. On the other hand favorable contingencies may overshadow the unfavorable ones and improve the value.

Gas

There are a few general items comprising general risk for gas companies which are peculiar to that industry.

Future Supply.—A company may have the opportunity, or perhaps the foresight to provide for the purchase of gas when

its own supply becomes diminished and thereby keep in use the pipe lines that would otherwise be salvaged. Where this possibility occurs, the transportation and distribution lines and certain other equipment will have a longer life than was originally expected. On the other hand, a case less likely to occur, is that of a company with an available market for over production or an opportunity to secure a new franchise and a new market, if the supply has permanently increased.

Market.—Like oil wells, the distance from a line often makes the sale of the product impossible or unprofitable. Isolated gas wells may return no income whatever because of the cost incident to connecting with a main line. Whether a company will develop a field of potential capacity in the hope of attracting a purchaser who will build a pipe line, or whether the company will drill only enough to insure the success of the line and then build it themselves, will of course depend on the capital and the market available.

Risk Table for Gas Wells.—A table should be made up from various groups of wells to show gas, dry hole and abandonment risks. With many small ga companies scattered throughout the gas producing areas, it becomes necessary to use such a table made up of many scattered wells. However, the amounts are much too general when using refinements in methods of appraisal. Such a table is better when conditions unde which the wells are completed are specified. As in the case of oil, at least three divisions should be made as follows:

1. Wells drilled not more than two locations from the producing well.
2. Wells drilled more than two locations from the producing well, but in developed or proven area.
3. Wells in undeveloped or "wild cat" areas.

Appraisal Of Oil And Gas Properties

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CHAPTER XV

COMPUTATIONS FOR APPRAISAL OF WELLS

OIL OR GAS

Source of Data.—After the appraisal has progressed to the stage where estimates of annual future production, future prices, future operating cost, the discount factor and risk have all been determined, the appraiser must choose the most rapid and accurate method for combining these to obtain the present worth of the property in question. To a slight degree, accuracy can be sacrificed for the sake of speed and economy. The appraisal computations consume a large portion of the time and therefore call for much attention to their simplification.

Usually a part of the oil, by the provisions of the lease and understanding with the lessor, is run into the pipe line to the credit of the lessor. This money never enters the hands of the company. In appraisal forms, therefore, the oil shown is that which accrues to the lessee or "working interest," as it is called, this comprises the net clean oil after deductions of the lessor or "royalty" interest. On the other hand, gross oil figures should be used in decline curve studies and the like, later attributing the royalty interest to the lessor, or holder thereof.

In the case of gas the lessor is rarely paid a royalty fraction. Even so it is usually paid in cash by the company rather than by "division order" (arrangement with pipeline company to directly pay the various interested parties, except in California) to a transportation company. If the producing company pays the gas royalty then the books and the valuation form should deal with gross gas and consider the gas royalty as a cost. More commonly the lessor is paid a fixed gas rental and this is entered in the books and appraisal form as a cost.

To obtain net oil from gross oil, some companies still divide by eight or six if the royalty is ⅛ or ⅙, respectively, and then subtract the quotient. The operation is greatly simplified by multiplying by the percentage of one's interest as 0.875 where there is ⅛ royalty and ⅞ working interest. The result is read from the reckoning table made for calculating royalties or by means of reckoning tables such as Crelle[1].

[1] Crelle, Dr. A. L., Calculating Tables, 1919, Walter De Gruyter & Co., Berlin, Germany.

The procedure in making computations for analytical appraisal of wells is: (1) Where future operating cost is taken by the well year:

Well No.............

1	2	3	4	5	6	7	8
Year	Future net production M. Cu. ft. or Bbls.	Future price $ or c	Value of product $	Future well year operating costs. $	Net income $	Discount factor for the year.	Present value
			2 x 3		4—5		6 x 7

Total present value of net income of well $ (Sum of column 8)

(2) Where operating cost is taken with the price to give the net profit per bbl. or per M. cu. ft.:

Well No.............

1	2	3	4	5	6
Year	Future net production per M. cu. ft. or bbls.	Future net income per M. cu. ft. or bbl. $ or c	Net income $	Discount factor for the year	Present value. $
			2 x 3		4 x 5

Total present value of expected net income of well $ (Sum of column 6)

Certain parts can be previously computed and much time saved thereby as follows: (3) The operating cost calculated as on well year basis—future prices and operating costs previously discounted.

Well No.............

1	2	3	4	5	6
Year	Future net production M. cu. ft. or bbls.	Future discount price $ or c	Discount income $	Discount operating cost $	Discount net income. $
			2 x 3		4—5

Total present value of expected net income of well $ (Sum of column 6)

(4) As in (3) except that the operating cost is previously found in cumulative discounted amounts.

Well No.............

1	2	3	4
Year	Future net production M. cu. ft. or bbls.	Future discounted price $ or c.	Discounted income. $
			2 x 3

Total discounted income ....$ (Sum of column 4)
Less Total discounted cost Operating .... $.................
Total net discounted income (present value) $.................

(5) Operating cost not on well year basis and combined with future price and the future net price so obtained is previously discounted.

Well No.............

1	2	3	4
Year	Future net production M. cu. ft. or bbls.	Future price less cost, discounted per M. cu. ft. or bbl.	Net present value $
			2 x 3

Total net present value .... $ (Sum of column 4)

Where many wells have a future life averaging twenty years, the amount of work involved in making the computation by plan (1) becomes enormous. Aside from that, the prices, production, discount factor and costs all have to be listed.

Of course the fifth method is the most rapid but not as accurate as those taking operating cost on a well year basis. By dividing the estimated annual production of the well for each year into the respective costs of operating, the cost in units of barrels or M. cu. ft., can be obtained. This means additional work and does not save time. Where prices and operating costs are to be referred to a number of times, it is better to have tables for each in which they are previously discounted. This eliminates the tedious step of copying the discount factor or of carrying out the multiplication thereof.

Computations by Chart.—In the compilation of a large report, it becomes necessary to adopt methods that will save time and where the final results will not be materially altered, especially when:

1. The available force of workers is limited, or

2. The cost of the work must not exceed a certain appropriation.

In the adoption of short cuts, the reduction of errors must be the foremost consideration. The use of charts has proved a time saver and is within rea-

sonable limits of error. In fact, the errors for the most part are both plus and minus and thereby compensate each other. Checks as to speed and accuracy have been found to justify the use of charts in extensive work, although the errors do not warrant their employment on individual lease appraisals for the purpose of purchase.

Three types of charts have been used with success.[2]

1. All valuation as of a fixed date.
2. Valuation as of various dates—all readings direct and no steps combined.
3. Valuations as of various dates—part of data previously computed.

The method of construction and use of each type of chart will be given. The operating cost in each case is on the well year basis because of the better results so obtained. If operating costs in barrels or M. cu. ft., are uniform throughout the life of the property, the charts could be greatly simplified. In order to rate wells, according to the size and number of producing sands, the entries are for one sand only, unless otherwise specified. Instead of the average production per well for decline curve construction, the average per sand has been determined. All sands are thus given the same rating. This is not theoretically correct but is more accurate than assuming well averages.

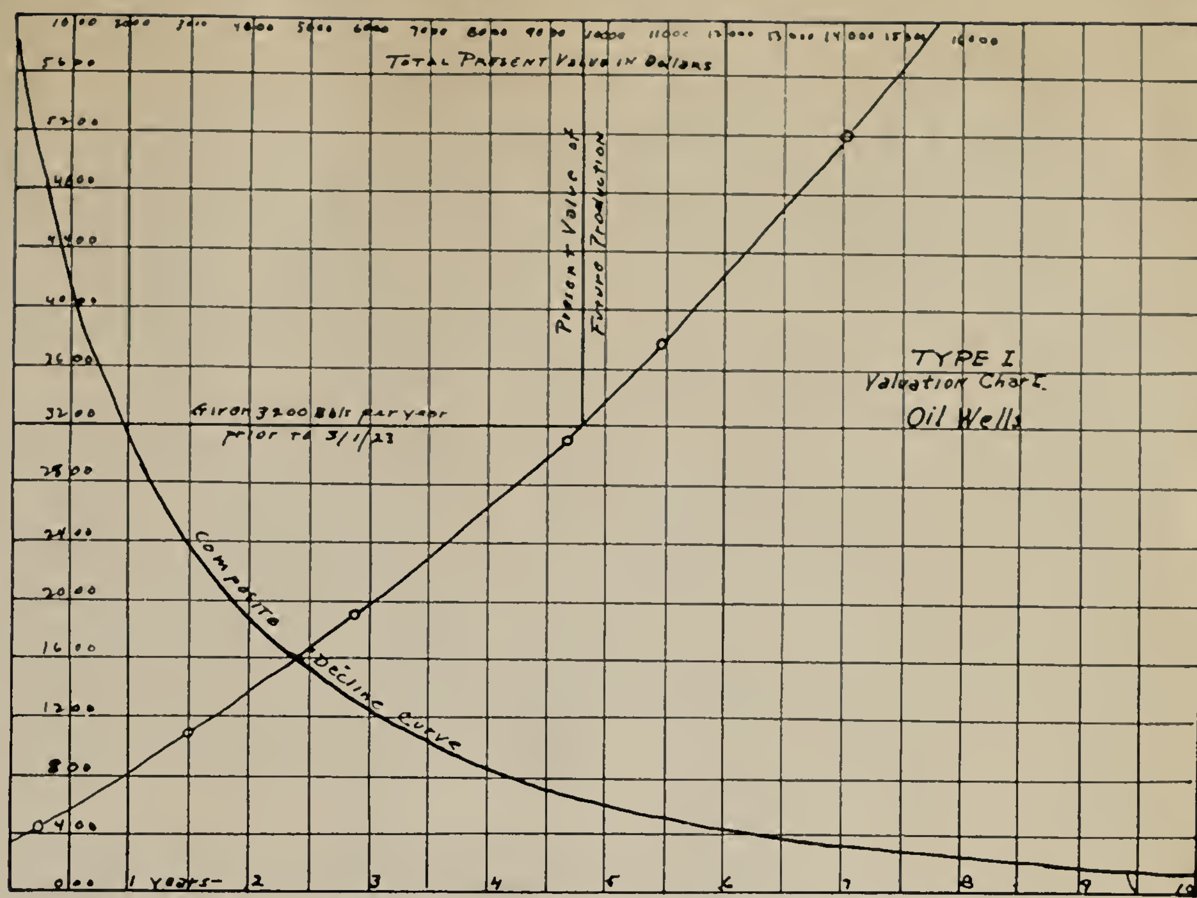

Fig. 32—Valuation chart where all valuations are as of a fixed date, as prepared for one pool. (After Reudemann, Bulletin A. A. P. G.)

1. All Valuations as of a Fixed Date.—To value a well, its production must first be determined from the decline curve. The amount to be expected in the future depends upon the size of the well. Where many wells are evaluated by obtaining future production from the same decline curves, there is a great deal of repetition. Wells of the same size give the same valuation. The valuations increase with the size of the wells on a curve approaching a straight line.

The valuation of a few theoretical wells, each of a different size, and from the same decline curve, give the amounts necessary to plot a curve. Given the latter curve, only the production, or other unit of measure, the year prior is required to obtain a valuation. This is a simple form of the curve and especially practical for oil.

Curve Type 1—Oil.—The curve in Figure 32 is one of this type made for one of the older pools. The points on the curve indicate the various sizes of wells valued to get the results necessary for the construction thereof. The total present value can be read on the upper scale. For actual valuation work, a larger scale would be desirable.

Gas.—In gas more than in oil, the number of producing sands varies from well to well, as does the number of tubings from which the production is drawn. The production, flowing from various horizons into one tubing will be included in the same tests. If it is a closed pressure test, it will be the average of the closed pressures of the sands, for where there is a common orifice, sands of a low pressure will be built up by sands of a higher pressure This adjustment takes place more at times when the wells are shut in than when flowing. (Referring to natural gas.) A production test includes the production of all the sands flowing through the same orifice. The amount attributable to any one sand cannot be segregated. Individual sands vary in productive quality to such an extent that it would be impossible to determine a fixed relation between sands in any specific locality. The assumption has therefore been made that each sand of a group shares equally the production shown by the test. Also, a well of a given closed pressure is likely to produce twice as much gas from two sands as it would from one. This latter as-

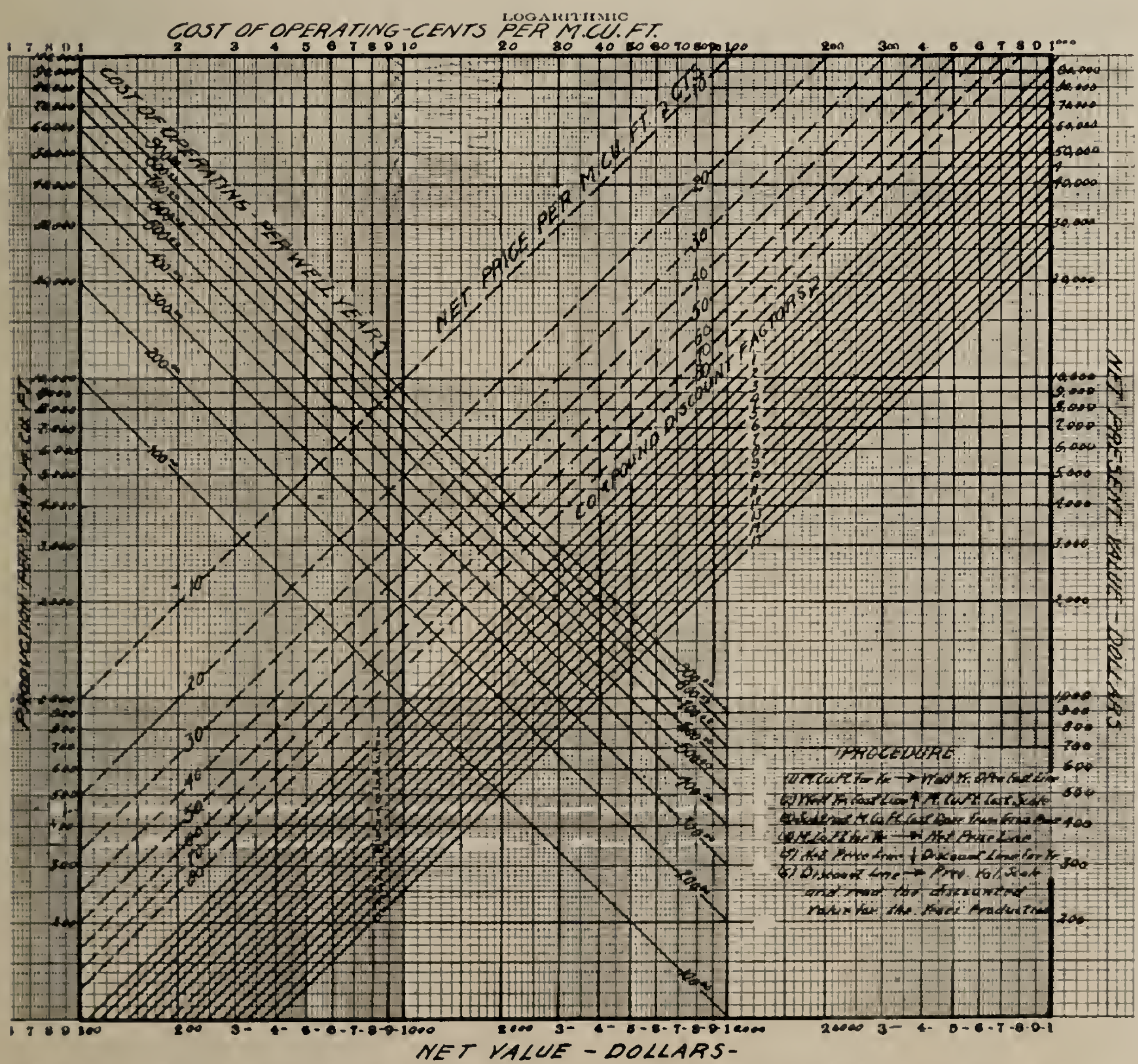

Fig. 33—Logarithmic chart for calculating value of gas wells under varying conditions. (After Ruedemann, Bull. A. A. P. G., 1922, but revised to apply for gas)

[2] Ruedemann, Paul. Charts for Appraisal of Oil Wells, read before meeting Amer. Assoc. Pet. Geol., March, 1922, and not yet published.

sumption should be checked by reference to reports of the drillers as the sands were penetrated.

2. Valuations as of Various Dates.—All the readings are direct.—With this chart the same procedure is carried out as that outlined in the tables under (1), but in a slightly different order. (See Fig. 33.) The examples are given for gas wells but can apply to oil by simply changing M. cu. ft. to net barrels and by changing the costs and prices accordingly.

The curves are plotted on logarithmic paper for convenience.. On quadrille paper the lines would radiate from a common point, zero, which makes interpolation awkward.

There are three sets of curves (a) operating cost per well year: (b) net profit per M. cu. ft., or barrel, and (c) compound discount factor.

The left scale is the production during the year in M. cu. ft.; the upper scale is the cost of operating per M. cu. ft.; the lower scale is the total net profit; and the right scale the discounted total net profit for the year.

Each set of curves is plotted with but little arithmetic calculation. In cost of operating groups, each cost line is located with reference to the left hand and upper scale. Three points can generally be plotted without much effort, for example, taking the cost of operating at $400 per well year, the amount in cents per M. cu. ft. for a well of 100,000 cu. ft. production is 0.004 cents; for a well of 10,000 cu. ft. production, it is 4 cents; and for a well of 1000 cu. ft. production, it is 40 cents per M. cu. ft. The same procedure is followed for the construction of other cost lines.

The line for net profit per M. cu. ft. is blotted with references to the left and lower scale. Points are determined as in case of operating costs with reference to the 100,000, 10,000 and 1000 cu. ft. production; for example, a production of 100,000 cu. ft. and net profit of one cent gives $1,000 and the others $100 and $10 net profit respectively. Other lines for two, three, four or more cents net profit per M. cu. ft. are plotted in a similar manner.

The compound discount factor group is plotted with reference to the lower and right scales; the lower being the net profit derived from the group of lines on net price and the right scale being discounted net profit desired. The discount factor for the first year is 0.95346. Profits of $10,000; $1,000, and $100 discounted for one year give $9,534.60; $953.46 and $95.34 respectively. Similar procedure is used for the 2nd, 3rd, 4th and additional years with their respective discount factors.

Example—Find the value of a well, given the following data:

Year	Predicted Production M. cu. ft.	Predicted Cost of Operating Per Well Year. $	Predicted Gross Price-Cents Per M. cu. ft. $
1	100,000	400.00	.05
2	50,000	450.00	.06
3	5,000	500.00	.07

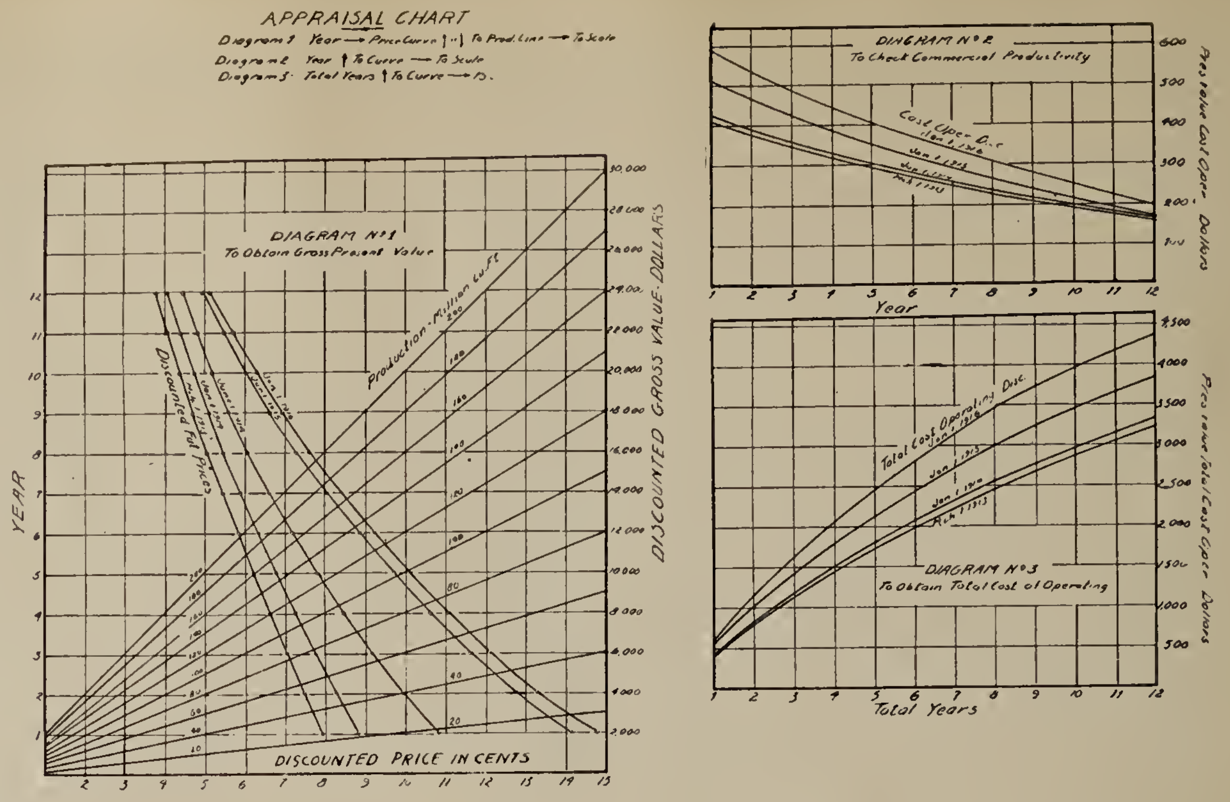

Fig. 34—Diagrams to compute value under same conditions as figure 33 but simplified by calculation of discounted future prices and operating costs and referring to them as dates and not amounts. (After Ruedemann, Bull. A. A. P. G., but revised to apply to gas)

Solution:

Start from the 100,000 point on the left scale, thence move horizontally to the right to the $400 cost of operating line, thence up, and obtain 0.04 cents as the cost of operating per M. cu. ft. The gross price is 5 cents and net price is the gross minus the cost of operating per M. cu. ft. or 4.6 cents net price. Continuing from the 100,000 point move horizontally to 4.6 cent net price thence vertically down to the first year discount line, thence horizontally to the right to the discounted net profit. The same operation is carried on for the second and third years, using the second and third discount lines respectively.

Answer:

Year	Discounted Net Profit.
1	$4340
2	2130
3	Non-commercial as cost of Operating is 10 cents per M.; gross price 7 cents per M.
Total	$6470 Value of Well

The production referred to in the example is for one sand. All production is reduced to the amount for each sand. Where a well produces from more than one sand,. the cost of operating is subtracted from the sand showing the longest life. No cost need be subtracted from the other sand valuations of the well. This is on the assumption that values are placed according to the number of producing sands.

3. Valuations as of Various Dates.—Discount Combined with Price and Cost of Operating—The simplest form of chart would be one in which, when the initial or the closed pressure and the date of completion are given, the valuation could be determined in one operation. Such a chart is possible, but is impracticable, as the formulae for each decline curve would be required.

The next simplest form of chart would be one in which the future prices are discounted and plotted by the dates and not as amounts, and the cost of operating is adjusted on one operation, separate from the computation of gross profit. The accompanying chart on quadrille paper (See Fig. 34) is one of this type. There are four sets of curves:

1. Discounted prices by months for each year.

2. Production.

3. Discounted total cost of operating.

4. Present value of the cost of operating to be used for ascertaining the commercial limit of the wells.

Diagram 1.—to Value Production.—Discounted prices are charted with reference to the left scale of years and the lower scale of discounted prices. Production lines are charted with reference to the lower scale of discounted price and the right scale of gross present value of production. For example, 10 million cubic feet at discounted price of one cent has a value of $100. 100 million cubic feet at five cents, a value of $500, etc.

The points plotted for one price curve fo''ow:

As of March 1, 1913

ɪ ear	Discount Factor 10%	Predicted Price in Cents.	Discounted Price in Cents.
1	.9535	8.4	7.91
4	.7163	9.2	6.59
8	.4893	10.3	5.04
12	.3342	11.4	3.82

Diagram No. 2.—To Check the Commercial Productivity of a Year's Production.—Toward the end of the life of a well a point is reached where the amount of production is insufficient to pay the cost of operating. This is the true economic limit. Many wells are operated that really produce less than the amount of gas necessary to meet expenses. The loss is made up by the company's commercial wells. It cannot be said that this gas has no value

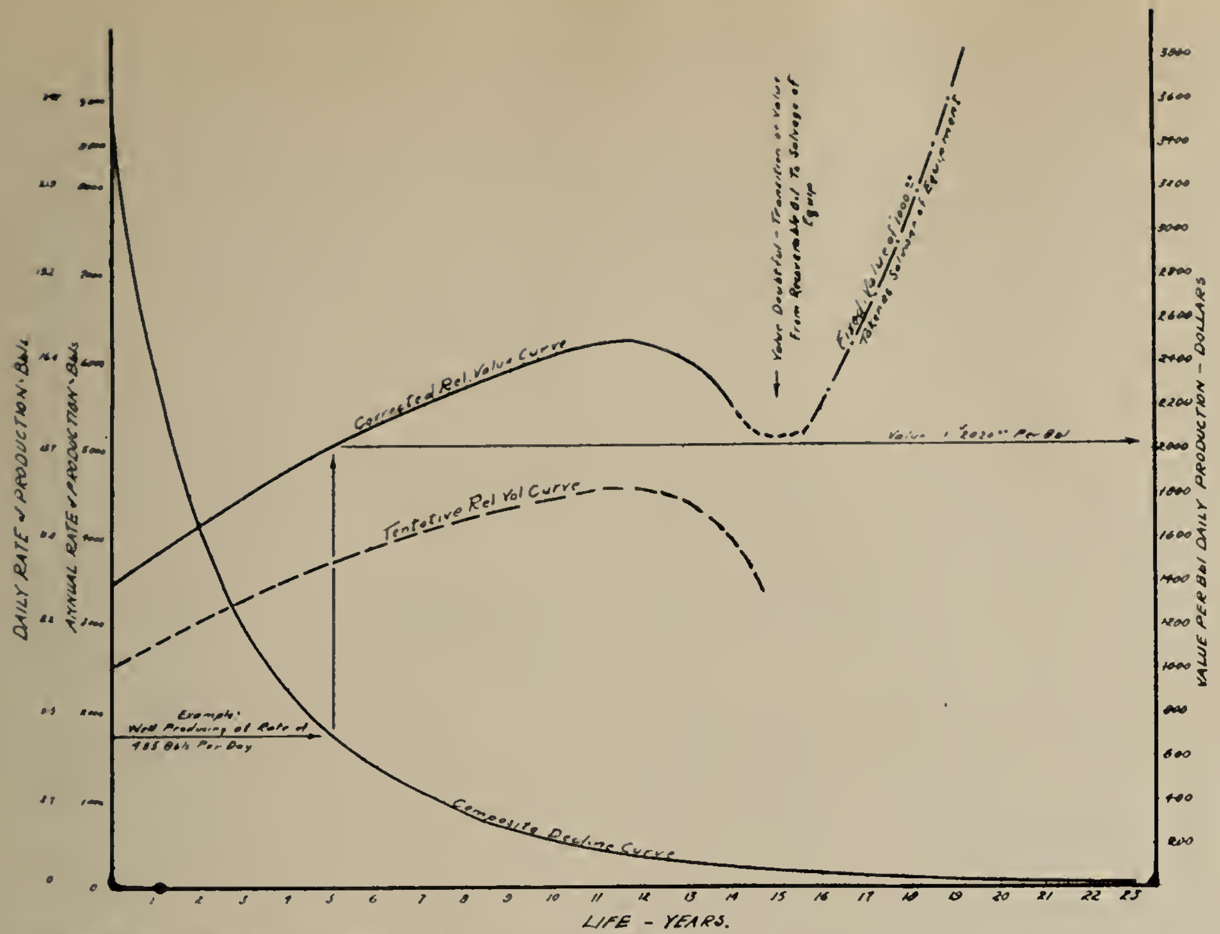

Fig. 35—Curve for obtaining the relative value of barrel day production in comparison to other properties in the same pool.

for by shifting the burden of the cost of operating, the greater volume of gas available for sale assists in meeting the demand. However, an average cost of operating per well is probably the best cost to use in valuation irrespective of this condition. The diagram is the discounted cost of operating as of March 1913, and January of each year thereafter. To find the discounted cost for a valuation as of some intervening month interpolate between the proper curves. The results are found with reference to the year, curve and the scale on the right.

Diagram No. 3.—To Obtain Total Cost of Operating.—This diagram gives the total future cost of operating as of March 1, 1913 and each year thereafter. The points are charted with reference to the total number of years on the lower scale and the total discounted cost on the right scale.

The amounts determined from the curve are to be subtracted from the total gross discounted value in order to get the net discounted value.

Example: What is the value of a well completed Jan. 1, 1914.—The future production estimated from the decline curve as follows:

Year	Production M. cu. ft.
1	100,000
2	50,000
3	5,000

Solution—Start at the left scale, thence move horizontally to the right to the Jan. 1, 1914 price curve, thence vertically upward to the 100,000 M. cu. ft. line, thence to the right and read the gross discounted value. For the second year proceed as above, only start at the second year point on the price curve and read up to the 50,000 M. cu. ft. line. For the last year it is necessary to ascertain whether the well is still commercially productive. The gross discounted value from diagram 1 is about $350. On diagram 2, start at the third year point, thence up to the Jan. 1, 1915 curve, thence to the right and read $360. The cost of operating is greater than the gross revenue. On diagram 3, find the total cost of operating for the two years of commercial productivity. Start at the two year point on the lower scale, thence up to the Jan. 1, 1914 curve and thence to the right and read the amount.

The value of the well is:

Years	Future Production M. cu. ft.	Gross Discounted Value from Diagram 1.
1	100,000	$8,800
2	50,000	4,200
3	5,000	350 Eliminated as cost of operation is $360.00.

$13.000 Gross present value
830 Total discounted cost of operating for two years.

$12.170 Net present value of expected income.

Advantages and Disadvantages of the Various Charts—Chart 1. This chart is quickly and accurately read when plotted to a large scale. It requires one person to read and tabulate. The usual number of operations in computing for a well of ten years of life when using a machine are 71. The multiplications require two persons and take, for the two about twenty minutes from start to finish. The use of this chart requires about two minutes for one person to get the result.

Chart 2—This is simple to construct but saves less time than the others. There are 61 operations as against 71 by machine multiplication, but the services of only one person are needed, thereby cutting the labor cost in half.

Chart 3—Quick and accurate.—No reference to prices or operating costs is required. For a well of ten year life, there are 13 operations by chart as against 61 by machine. Here, too, the services of but one person are needed with a saving of time between 80 and 90 per cent.

Additonal Factors to Consider.—The discussion in this chapter is mainly for valuation by the analytic method. Primarily a property's worth for purchase, sale, or other disposition is directly dependent upon future earnings. The earnings may not be entirely from the operation of the holdings, but on the contrary may arise from the sale of the equipment. Producing tracts with a productive life shorter than the life of the equipment, promise income from the salvaging of the physical property. Therefore, on such tracts, the present value of the future net earnings, plus the present value of the salvage, constitutes the total value of the tract. In such cases, that portion of the value of the equipment subject to depreciation on date of appraisal, is the difference between the total value at that time and the amount of present value of the salvage as defined above. Salvage is therefore a future income derived from the fact that the equipment in some degree has a longer life for the same or other purpose than that of the resource.

Appraisal of Undrilled Wells.—This discussion has so far touched upon the procedure in the appraisal of producing wells. There are two other types of valuation to be considered, namely, (a) undrilled wells on which reserves can be postulated and (b) undeveloped acreage on which any oil or gas content cannot be estimated. The latter case is discussed in Chapter XV.

Locations are generally predicted near producing wells. In some cases a

(For Reference to this Table see middle Column, Page 58)

A Annual Rate of Production Bbl.	B Daily Rate of Production Bbl.	C Future Estimated Production. Bbl.	D Percentage of Reserves remaining to those of the largest well.	E Value remaining $	F Tentative barrel—day Value. $	G Value in relation to a reference transaction $
9000	24.7	23,460	100	24,700	1,000	1360
7000	19.2	20,300	81.5	21,300	1,110	1510
6000	16.4	18,200	77.5	19,100	1,170	1590
5000	13.7	16,070	68.5	16,900	1,230	1675
4000	11.0	13,750	58.5	14,450	1,314	1790
3000	8.2	11,000	47.	11,570	1,410	1920
2000	5.5	7,900	33.6	8,300	1,510	2060
1500	4.1	5,800	24.6	6,100	1,490	2030
1000	2.7	4,050	17 35	4,250	1,530	2080
800	2.2	3,450	14.7	3,620	1,650	2240
600	1.64	2,700	11.5	2,840	1,730	2350
400	1.09	1,900	8.1	2,000	1,835	2500
300	0.823	1,400	5.95	1,470	1,790	2440
200	0.55	700	2.98	735	1,340	320

prospective pool may give reasonable assurance of production and warrant an estimation of the reserve. However, the hazard involved in the determination of the underground content where the locality is distant from production is so great that methods such as comparison with market value, pore space computations and others are more advisable than analytic appraisal. In valuing locations to be drilled the procedure is:

1. Outline a drilling program and thus obtain the probable date of the completion of each well.

2. In accordance with the location, calculate the risk on dry holes.

3. From the history of the initial production of all wells in the vicinity or of wells that are most similar (with some modification if indicated) find the probable initial capacity of each well.

4. On the basis of (3) ascertain the future production by years.

With future prices, operating cost, and discount factor, find present value of the production by the same procedure as for the producing wells. As an alternative, if the proposed well is to be completed in time to have the probable future production comparable with some producing well, the present value of such comparable producing well less deferment can be taken, either directly or with modifications.

6. Apply risk factors.

7. Subtract present value of future cost of development if it has not been previously provided for in the calculation of net receipts.

OIL

The Barrel-day Unit of Value[1].—The occasion often arises when the barrel-day value of a certain property is desired. As a rule such a value is determined by the opinions of the contracting parties, using as a guide ten dollars per barrel day value for each cent of market price of oil. The barrel day unit is a definite number of dollars for each barrel produced in one day. Thus if a barrel-day value is $1000 a property producing 200 barrels a day has a value of $200,000.

In placing valuations on properties for taxation purposes, the requirement is that the value be the fair market value determined by appraisal, comparison with properties sold in the vicinity, or any other method satisfactory to the Commissioner of Internal Revenue.

Where a comparison with sales is used, the transaction or transactions consummated must have been between a willing seller and a willing buyer. "Speculative value" that is, a value not realizable by sale, cannot enter into the market value.

The engineer called upon to establish valuations by the use of sales has first to find a property that can be used as a basis for comparison. The primary consideration is the size and age of the wells on the properties being compared. The wells on the property sold may be much younger or older than those on the property to be valued. Obviously, the same barrel-day value cannot be given to each. In order to facilitate comparison and to eliminate the unallowable factor of opinion, a curve, to be designated as "Relative Value Curve," has been devised. It has as its foundation the composite decline curve for the region, and arithmetically fixes barrel-day values for units of various sizes in relation to a given well or wells.

The accompanying diagram is an illustration taken from one of the decline curves in the Appalachian field. Points for the Relative Value Curve were obtained by computations as shown in the two column table at the bottom of page 90.

A—Annual rate at which a well is producing.

B—Amount in A reduced to barrels per day.

C—Total future reserves for a well that is producing at the rate of the well given in A.

D—Per cent of the reserves remaining in relation to the future reserves of a 9000 barrel well.

E—Value of $1000 per barrel day was assumed for the 9000 barrel well, or $27,800. Each other well is given a value proportionate to the percentage relation between D and the largest value.

This fixes a total value in relation to reserves.

F—The value in E for each well divided by the average barrels per day in B.

G—It has been assumed that a transaction occurred in the vicinity of wells averaging 7000 barrels the year prior to the date of sale. The price paid was $1510 per barrel day. Each barrel day value in F is, therefore, increased in the ratio of 1510 to 1110 and a new barrel day value found for each well commensurate with the transaction price.

The curve in the illustration is made up from the points in G above. Values are plotted vertically above the decline curve and can be found by a procedure illustrated by the arrows. Since the reserves were not carefully estimated, the points are not as regular as normally.

As a well approaches maturity its worth becomes more a matter of the salvage value of its physical property than of the recoverable oil. The normal course of the barrel-day price is an advance until a maximum is reached in middle age followed by a decline until late middle age and then followed by an advance up to the time of abandonment.

Having obtained the value per barrel-day in relation to the transaction price, it is necessary to increase or decrease the amount in accordance with the difference in reserve acreage, age, (sometimes), state of equipment, location on structure, and numerous other factors. This changing of value will be more or less arbitrary and depends entirely upon the merits of the respective properties.

[1] Ruedemann, Paul Comparative Barrel Day Values in Different Sized Wells; Nat. Pet. News, June 21, 1922, pp. 73-75.

Appraisal Of Oil And Gas Properties

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CHAPTER XVI

VALUATION OF UNDEVELOPED ACREAGE

Oil or Gas

Definition and Explanation.—The term undeveloped acreage when here used refers to leases or tracts commonly known as prospective or reserve leases, which are here differentiated from "protective" or undrilled acreage adjacent to, or in the immediate vicinity of producing wells and especially acreage in the same lease which has wells elsewhere upon it. The chapter on "Estimation of Future Yield—Producing Wells," discusses the basis of calculating reserves for all but the undeveloped acreage as herein defined, and the chapter on "Well Appraisal Computations" discusses the method of valuing. There may be instances where analytic methods cannot be applied to acreage adjacent to or near producing wells and the methods to be suggested are applicable.

Right to Value Leaseholds.—The contention was at one time that a lessee had no equity in the oil or gas reserves until the drilling of a hole revealed presence of the resource, and then his equity pertained only to such oil or gas as had been recovered. The Bureau of Internal Revenue upheld this view and permitted no valuation to lessees for depletion purposes until after 1917. A large number of court decisions since have maintained that the right to drill for gas constitutes an interest in the land itself and is necessarily an exclusive property right.[1]

It can therefore, be assumed that the right of the particular oil or natural gas company being appraised to claim valuation for leaseholds, especially for rate-making cases, has been thoroughly established. For the purpose of purchase or sale the right is obvious and has never been questioned, and properties change ownership on the basis of the value of these rights.

Value and Market Price.—Oil leases are continually changing ownership on the open market but gas leases are very infrequently transferred. In event of transfer, if there is a willing seller and a willing buyer, each with a knowledge of the inherent value of the property, then a basis for valuation in the particular area is established. The qualification of a willing seller and a willing buyer does not always exist, for as a rule, in the change of ownership, the vendor, although aware of the potential value, sells at a lower price because through lack of capital, marketing difficulties or otherwise, the sale of the lease is necessary, and the vendee, being in the most advantageous position, gains control. The conditions relative to establishing a fair market are apparently there, but the true value has not been revealed by the transaction. Sheriff sales and other such disposals do not constitute "Fair Market Values." So few gas leases exchange hands that the geographical and geological difference of location of leases must be taken into account and an adjustment of the determined sale price of a particular lease made to suit the leases under examination. Such adjustment would be arbitrary and dependent largely upon the opinion of the appraiser.

Valuation by Comparison.—In a few isolated instances, it is possible to determine the valuation by comparison with producing areas. The geological conditions may be such that there is a likelihood of finding similar amounts of oil or gas per acre to that revealed in a nearby pool or property. Still considerable calculation would be involved, for after the probable quantity has been established, the rate of extraction, cost of development, operating expenses, sale price, hazard or investment risk and many other factors need to be ascertained. If one could count on the uniformity of the texture of sand over large areas, the determination of underground reserves by similarity of pore space might be helpful, the amount of pore space being fixed by that found in producing wells in the same sand in the field being used for comparison. The salt water situation might offer a serious handicap to the valuation in this case, if the sand carried encroaching water.

Valuation by Analyses of All Conditions.—The best method for valuing undeveloped acreage is that which is as near annual analytical appraisal, with proper determination of risk, as is possible. The comparison with sales price is far less significant than comparison with oil or gas lands, the productive history of which is known, so that its value can be calculated.

The elements to be considered are in the fields of geology, engineering and economics. A collective analysis of the factors should form the basis of the expert's appraisal. The fundamental elements, with a discussion of each, are as follows:[2]

A—Geology.

1—Nature of the reservoir, which includes effective porosity, thickness and lateral regularity of the sand. Some of these are not always exactly determinable. However, some estimation of the probable conditions should be made, as this and the following are the most fundamental factors.

2—The attitude of the beds, by a geological structure map, showing the location of the lease or leases on the fold, if any, and the probable oil or water line.

B—Engineering.

1—Volume of flow; an estimate of the amount of oil or gas the wells will produce.

2—Probable life of the field, which depends upon the rate of extraction, depth, thickness and character of the sand, the volume and pressure, all dependent upon comparison with experience in a field with approximately the same conditions.

3—Pressure; whether the closed pressure is likely to be high or low, as both pressure and volume influence the cost of producing oil or gas, especially gas because wells of small volume and low pressure require more expensive transportation facilities to supply a given amount of gas.

4—Character of oil or gas; whether containing sulphur or other deleterious substances, whether rich or poor in gasoline, and whether the wells are likely to be affected by salt water.

C—Economics.

1—The grouping of leases; a large block has obvious advantages once production starts, but before production the proximity of the tests drilled by others is of advantage.

2—Character of competition; a field free of competitors can be more economically developed and the supply can more readily be conserved, when all leases are controlled, or nearly controlled, by one company.

3—Cost of drilling wells; whether the accessibility of the lease and the depth of the sand warrant exploitation on the basis of the present market. The depth of the sand has a large influence on future development costs and consequently on the value of the lease.

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[1] Wyer, S. S., Principles of Natural Gas Leasehold Valuation. Trans, Amer. Inst. Min. Eng., Vol. LVI (1916), pp. 782.

[2] Reeser, H. C., Value of Leaseholds for Rate Making Purposes, Proceedings of Nat. Gas Assoc. of Amer. Vol. VIII, 1916, pp. 344-349.

4—History of surrounding development; an investment risk depends largely upon the proportion of dry holes to producing wells in the producing horizon.

5—Proximity to developed territory; the value of acreage decreases with the increase of distance from producing territory because of the increasing hazard.

6—Proximity to market; whether the market is relatively close or distant and the degree of accessibility.

7—The market demand; whether industrial or domestic, the population and probable future demand.

After a thorough study of these factors and of other minor ones peculiar to the region has been made, it devolves upon the appraiser to fix an acreage value. If some reasonably reliable estimate of the quantity of oil or gas available can be made, and the risk adequately determined, the future price, operating expenses and cost of development will offer no great difficulties, so that a valuation can be made by the regular methods and reduced to the proper amount per acre. Otherwise an average price may be obtained without an analytic appraisal, based on a profit and loss analysis of large acreages which have been exploited.

Valuation by Prevailing Market Price.—Irrespective of the refinement possible in fixing value most acreage is transferred at amounts determined by persons competent to judge market values. The chief of the land department in large companies generally is so well versed on the trading price of leases that a valuation is unnecessary although warranted. Of course most tracts so purchased are obtained at a figure sufficiently low to allow a good margin of profit. Where the value is comparatively large the opinions of several persons of experience and judgment are usually combined.

These values are exchange value and not the more important productive value, which is what the company desires to know when requesting a valuation.

It must be remembered that in disposing of holdings the price to be expected is more often the exchange value than the potential value. Obviously, this will not be true when the more scientific methods have gained greater prominence.

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CHAPTER XVII.

VALUATION OF PHYSICAL PROPERTY

Oil or Gas

Purpose of Valuation

THE valuation of physical property in the oil or gas industries offers relatively few specific problems, and general rules of appraisal apply to it for the most part. The discussion is therefore more cursory than that of the operating cost and income. The valuation of the producing division differs in oil companies from the refinery, pipe line and other equipment valuations; and for gas, from the transportation and distribution divisions because:

(a) A production plant is valued by the expected returns from earnings from devolped and undeveloped areas. In the appraisal of wells, the limitation is the amount of oil or gas "in sight." But further development may contribute more oil or gas elsewhere which may prolong the life of the company and its non-producing plant. This succession of migrations from exhausted to new productive areas is essential to a "going" company.

(b) Refineries, oil pipe lines, and transportation and distribution lines for gas, have a longer life than the wells, since exhaustion of the company's reserve does not at all terminate the usefulness of this class of physical property. There is always the possibility that a company can obtain from other sources, sufficient amount of oil or gas to meet the demand, and whenever this is no longer available, they may use the lines for further purposes as in the case of natural gas, for piping a substitute gas. The latter would be a gradual transition.

Relation of Earnings to Value.—The earning power of the production system definitely establishes its value. The physical equipment necessary to produce oil or gas generally does not change this value but merely makes it possible. However, a nearly exhausted property whose equipment has a remaining life of usefulness longer than that of the well, has a value in excess of its earning power because of the salvage value of the equipment. On the other hand, the value of physical equipment on some mature producing wells may have decreased to a vanishing point and can be ignored where it is certain to be no longer usable or if the market is such that its disposition is impossible.

For refineries, transportation lines and other similar equipment, the earning power should establish the value. The present situation of the industry precludes estimation of future earnings with the exactness essential to a reliable appraisal, except where the supply of oil or gas is ascertainable and it is certain that no further supply can be expected.

In the case of gas, where the natural supply is limited, the lines can usually be maintained later for the distribution of artificial gas. A different schedule of rates, operating expenses and investment will be introduced with this change. A plant to produce artificial gas necessitates a large expenditure. The expense of manufacturing this substitute for each average foot sold, generally exceeds the cost of recovering the same unit of natural gas. The uncertainties incident to postulating the cost, operating expenses and returns from artificial gas at a distant date are so great that such an appraisal is rarely attempted unless the change is likely to occur in the immediate future.

Cost of Reproduction or Replacement.—The best guide to the fair value of a property is generally the value in the condition at time of appraisal. The type of method used in arriving at this value depends, as a rule, upon the age of the plant. A plant established a comparatively few years prior to the date of appraisal, that is, recently enough to have been purchased under market conditions almost similar to those prevailing at the valuation date, should be taken at its original cost minus depreciation. On the other hand the value of an old property would depend largely upon the cost to reproduce the property.

In making the valuation of physical properties, numerous factors must be taken into account, some of which are:

1. The cost of replacing each inventoried article with an article alike in kind and service.

2. The probable term of usefulness of the article.

3. The probable term of usefulness of the replaced article.

4. In the case of valuation for purchase of sale, account should be taken of the accrued depreciation, which will aid in determining the value of the equipment.

Cost to Reproduce and Appreciation When the replacement cost is used as a basis for determining the value of the investment, a certain amount of appreciation may be involved by use of current or recent prices. The enhanced value being due to the present increased cost of materials, labor or change in conditions. Where such appreciation occurs, it is unearned increment. Of course occasionally cases arise where values in terms of dollars decrease and there is no unearned increment.

The question as to whether unearned increment is to be added to the investment depends largely upon the fairness of its addition and the purpose of the appraisal. The inclusion of appreciation for rate cases is sometimes challenged. However, for purchase or sale, or appraisals of similar significance, appreciation is a factor of much importance.

Depreciation in the Valuation.—When equipment is valued for some purposes, depreciation becomes an important consideration. The numerous methods in use, both practical and impractical, are outlined in the chapter on "Computation of Depreciation." These can be applied where suitable, for the calculation of depreciated values. The intention is not to find the annual depreciation but the current value of the physical property of the plant. Various methods are advocated of which the inventory and cost of replacements has been discussed. Several authorities use simple methods for approximating the value sought for. Of these methods the "Arbitrary Percentage Method" and the "Unlimited Life Method" are practical and easily applied.

Arbitrary Percentage Method.—This is more or less a "rule of thumb" process if obtaining reproduction or replacement value. It is convenient and inexpensive, but must be used with caution, and only under certain conditions. In the first place, it is based on the assumption that the class of equipment is worth its cost less the salvage, and less some percentage, commonly fifty per cent. This method can be used only when the class of equipment under valuation comprises a large number of units and it must have been in operation for some time, at any rate for five years. The older the property the more applicable is this method. Repairs and replacements must have been going on continuously so that new, and all stages of deteriorated units, make up the whole. A telephone line will comprise such units, if in operation long enough, likewise the household meters if not subject to obsolence or inadequacy. It is to be observed that the method is quite fallacious if applied to some

classes of equipment. If it were applied to the well equipment of a small company or group, it would prove disastrous. To be applicable to wells the condition of uniform addition of new similar wells would be essential, and this is never found.

Unlimited Life Method.[1]—This method is very similar to that described as "Insurance Method" in Chapter XX. It is based on the assumption that a public service property is being kept in good condition by the repair and replacement of its parts. Thus the whole takes on an unlimited life, in which no part of the investment need be returned to the owner, but as the plant becomes older a return must be made from revenue for the cost of each article replaced. As the plant reaches the stage where growth has ceased, the annual amounts required for repairs and replacements will average the same as depreciation by the straight line method.

The valuation by this method will necessarily be the original investment without allowance for depreciation. The replacement requirements will be approximated from the estimated cost of the comprising units, with due allowance being made for age and the probable new life of the individual parts of which the property is made up. When, by experience, the replacement requirements can be definitely ascertained, then the equivalent of annual depreciation chargeable against the property would be simply the expenditure for repairs and replacements.

Depletion and Physical Property Valuation.—Inasmuch as the value of production depends upon the present worth of future earnings to be derived therefrom, considerable time can be saved by valuing the equipment necessary to create these earnings at depreciated cost. The difference between the total present worth and this equipment investment establishes the value of the resource, which is the depletable value. Using replacement or appreciated value of equipment only decreases the value of the oil or gas reserves by a larger amount and so does not add to the total value.

Final Valuation.—If the present worth of the company's assets has been ascertained by the discounting of future earnings, only the value of physical property, not directly attributable to the earning of this income, and the salvage value of excess equipment need be added to obtain the total value.

It has been shown that it is hardly practicable for a natural gas company to use annual analytical appraisal principles throughout, when it has a transportation and/ distributing system as well as a producing system. This also applies to an oil company with pipe lines or refinery. It is better to segregate the whole plant into the three systems and to apply that method which is most practical and accurate for each. After the valuations for each of the various units are found, it is then necessary to make totals, apply risks, etc. The operations in relative order are:

1. List of values of producing wells.
   (a) Adjust the value of each producing well by the risk of premature abandonment, if necessary.
2. Valuation of locations.
   (a) Apply dry hole abandonment and deferment reduction factors, if not already taken.
3. List the value of gasoline plant or other supplementary values.
4. Value the undeveloped acreage.
5. Find the value of well and lease equipment.
6. Find the present worth of salvage value of the excess equipment of (5).
7. Find values of transportation and distribution lines (gas).
8. Find value of physical property not in 5, 6, or 7.
9. Get a summary of the company's tangible property. (5 is involved in 1 if values of production are in the field. All equipment is in 1 if the value of production of gas company is at a distribution point.)
10. On a basis of 9, make an allowance for going concern value. (This may be automatically provided for, especially where the annual analytical appraisal method is used throughout.)

CHAPTER XVIII

VALUATION OF INTANGIBLES

Oil or Gas

Intangibles to Be Valued

THE term as applied to appraisal in general, agrees with the federal use of the word, namely that it covers elements other than those of a physical nature. The value of oil or gas reserves is tangible, along with the physical property, whether held under lease or fee. Among the intangibles are, "franchise," "good will," "going value," "going concern value," "rights-of-way," "right of ingress and egress," and the like. The values in question arise out of the organizing and establishing of a revenue earning business.

Good-Will

"Good will" and "going value" are closely related. No "good will" is recognized unless an industry has competition with other like business ventures. Where a gas company is the sole distributor, there is a condition similar to a monopoly and customers are retained by compulsion or necessity, rather than from choice. In regular sales to a pipe line, there is practically no good will.

Going Value

This term, commonly confused with "going concern value," attaches to business enterprises in operation. Defined broadly, it is the cost to the owner to bring the business to a self-supporting basis. The early history of a gas company reveals much "going value." Dry holes drilled before production is found in sufficient quantities to pay expenses, interest on the plant during time of construction, or other losses are all included under this value. For computation of invested capital for mining companies, the federal tax regulations specify that all charges up until the plant earns sufficient to pay operating expenses, are investment. Thus, "going value" is properly charged to the investment, although made up of items ordinarily considered expense.

Early deficiencies of earnings may sometimes be compensated for by the method of accounting for losses. It is difficult to determine definitely the amount of "going value."

Going Concern Value

This is much broader than "going value" as it covers value resulting from successful operation and harmonious organization. "Going concern value" is that amount in excess of physical and depletable value which it would take to duplicate or replace an existing plant to its present efficiency. It depends upon the length of time necessary to reconstruct the plant and the time and cost after construction to bring it to the equivalent of the present one as to the volume of business and earnings. However, one plant may vary greatly from another due to quality of personnel, although other things are equal.

Franchise

A franchise is a privilege granted by a community by agreement or through legislative authority, permitting the carrying on of a particular business in a locality. There is a similarity between the "good will" of a private business and the franchise of a public utility. In large cities, where several gas companies compete, both "good will" and franchise values exist. Where there is no competition, franchise value alone comes under category of intangibles. In any case the valuation of franchise privilege is affected by the stipulations and agreements coming thereunder. A perpetual franchise has greater value to the busines than one of short duration, for in addition to the obvious advantage, it permits the planning of an operation program for years ahead. The amount of protection against competition, the rate stipulation, service charge limitations, and the like, indicate freedom of operation and consequently they affect the franchise value.

Rights-of-way

The rights-of-way are more valuable in the case of railroads and pipe lines than for natural gas utilities. However, in the case of gas transmission lines and of oil pipe lines, the establishing of a right-of-way through a particular locality may mean an enormous saving in construction cost. In regions where these rights are readily granted, little value attaches to them other than their cost.

[1]Grunsky, C. E., Valuation, Depreciation and Rate-Base, pp. 166-167.

On the other hand, where an antagonistic feeling toward such an enterprise exists the possession of advantageous rights-of-way is a value of real consequence.

Leaseholds

Leaseholds when valued because of a fortunate arrangement or the grouping of leases, brought about by combining the ownership of several units, constitutes amount of intangible value. Where a company enjoys more than the ordinary amount of protection against drainage and competitive drilling this allowance for intangible value should be made.

Valuation Multiples for Intangibles

In some instances the practice is to consider intangibles, such as rights-of-way, etc., by a valuation multiple of the value of adjacent lands of like character. The multiple varies in accordance with the factors fixing it for the locality, and may be from a fraction to several times that of the normal market value. Leaseholds, under certain conditions, may be increased over yield value by such a multiple. Not uncommonly the total intangible value of a business is stated as a multiple of the purely physical value.

Where valuation is based wholly on future earnings, all intangible value would seem to be automatically provided for. The future revenue is the direct result of the organizations ability to create income. Without the "going concern value" and "good will," the postulated receipts would be of no consequence. Thus no intangible value, as such, attaches to valuations made of the bare plant as an non-operating mass of physical property, real estate and gas rights. The addition of intangible value provides for the effort resulting in profit from the operation of the tangible assets.

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CHAPTER XIX

COMPUTATION OF DEPLETION

Oil or Gas

Explanation of Depletion

BOTH oil and gas are wasting assets. Once they have been removed from the underground reservoir, the oil and gas rights lose all value. If there is replacement, it occurs too slowly to be a factor in any estimation. Each unit extracted diminishes the reserves by just that amount. Therefore, any investment should take into account the limit of supply and the return of capital, in general distributed according to the rate of recovery of the product. The term depletion allowance is applied to this return of the investment. Production represents depletion, but the rate depends on the percentage of oil or gas recovered as compared with the ultimate amount recoverable as calculated for the time of the investment.

An estimate of the amount of recoverable oil or gas made at the early life of the property is subject to revision as subsequent production may bring out the fallacies of the earlier assumptions. However, under favorable conditions, reasonable approximations can be made and used with satisfaction in the keeping of accounts.

Rate of Depletion.—An oil or gas property declines more rapidly in its early life than in later life. The major portion of the production is recovered in the first few years, in fact, one half is usually obtained by the end of the first or second year. Consequently, charges for depletion should be high when the production is high. The more speculative estimate of the reserve the sooner should the investment be retired. When there is but one well on a property large enough to support more than one, the total cost of the property should not be refunded by that one well, but a share of its cost, commensurate with the probable reserve of the proposed wells, should be set aside to be retired by them.

Capital Returned Before Income.—A practice common among many producers is to consider that no profits are earned until all the capital invested has been returned, that is, the property must "pay out" first. This is an ultra-conservative attitude, especially in regions where little speculation exists in the estimate of reserves. This practice is not permitted in reports to accompany income tax returns.

Outline of Depletion Methods.—The following are among the many methods of computing depletion allowance.[1]

(1) To endeavor to periodically "charge off" a percentage of the investment in the property equal to the proportion of oil or gas withdrawn. This procedure requires a reliable estimate of recoverable reserves.

(2) To periodically "charge off" as much depletion as the concern can afford, until the existence of sufficient recoverable oil or gas content has been proven to justify the charging off of the balance in accordance with the estimated recoverable content.

(3) To estimate the number of years during which the property may produce, and to reduce the investment in equal installments on that basis. This method places too great a burden on the later life of the property, unless production from new wells, coming in during a considerable part of the life of the tract, can maintain a uniform total production, so that each depletion charge will be made against approximately equal production.

A Real Unit of Depletion.—The degree of accuracy possible in depletion computations depends in part upon the company well records and accounting system. Depletion, like depreciation, is often kept in separate lease accounts. The company endeavors to return capital on each property in accordance with the decline of production on that particular tract. This is much more readily handled in oil than in gas producing properties, for (1) gas properties do not support as many wells, there being generally only one to a lease, (2) records of gas well production are often unreliable estimates, and need to be combined with similar tests on other wells to obtain an average and (3) the depletable investment in gas wells is normally quite light, especially the bonus which, because of its lesser size, is usually charged to expense.

Depletable Invested Capital.—The items comprising investment subject to depletion, other than the cost of the physical property, are those spent in securing and bringing the lease to a state of production. The usual expenditures returnable through depletion are bonuses, legal and other expenses in the securing of leases, engineering and geological costs in the examination thereof, rentals to the time production commences, and the cost of drilling, with such incidental expenses as fuel and water. The cost of drilling is variously handled as an expense, depletable capital or as a depreciable item. Prescribed accounting systems for natural gas companies of Pennsylvania specify that the drilling cost be included in investments. For federal taxation the method is optional. Bonuses and rentals usually find their way into current expense accounts, but rightfully belong in the account for depletable capital.

Depletion on Capital Sum.—The term "capital sum" is used by the Federal Government to designate deleption on valuation as of March 1, 1913, or later, when permitted for "discovery." Capital sum distinguishes valuation depletable amounts from invested capital depletable amounts.

Depletion by Percentage Decline.—Instead of reducing depletable investment or "capital sum" to units of barrels each year, the percentage of production for the year to the ultimate production at the beginning of the year is sometimes taken. However, the invested captial or capital sum used should be as of the beginning of the year. Nevertheless a unit cost is desirable, as it reflects the portion of the unit sale price that must cover operating charges and profit.

Depletion by Decline in Flow.—A method now recognized as incorrect, and which has become obsolete, is that used by the Government on decline in flow. Prior to 1918 it was permitted to calculate depletion on the "actual reduction in flow and production." Thus where there was no reduction in flow, as is very commonly the case on properties being developed, no depletion could be claimed, although there was oil recovered and sold from the property. Furthermore the depletion rate cannot be stated in percentages of the year prior.

Percentage of Depletion Curve.—For convenience, especially where the rate of depletion of many properties, all based on the same decline curve, is required, a series of curves will greatly facilitate the work.[1]

To construct this chart, find the percentage of the ultimate amount of oil recovered at the end of each year, for wells having varying production the first

[1]Smith, C. G. Cost Accounting for Oil Producers, Bull. 158, Pet. Tech. 43, Bureau of Mines, p. 115.

[1]Lewis, J. O. and Beal, C. H. Some New Methods for Estimating the Future Production of Oil Wells: Trans. Am. Inst. Min. Eng., Vol. 59, 1918, p. 615, and repeated with changes in "Decline and Ultimate Production of Oil Wells, with notes on Valuation of Oil Properties," by C. H. Beal, Bureau of Mines, Bull. 177, Pet. Tech. 51, 1919, pp. 101-103.

year. The points for each year are plotted on co-ordinate paper, using a lower scale average daily production the first year, and an ordinate scale of percentage of ultimate production per well obtained at the end of each year. All points representing the first year are connected by a smooth line, and similarly for each successive year.

The appraiser or accountant seeking the percentage of oil recovered need only to refer to the chart and the percentage is available as a lump sum. If the recovery for a particular year, and not that for the life of the well to that year, is desired, find the percentage of total recovery to the year in question and also for the one prior, and by subtraction obtain the percentage for the year desired.

Realized Appreciation.—This is another term used in connection with depletion and depreciation computations for Federal tax deduction. The law prescribes that in certain years, and under certain conditions, a taxpayer may deduct an amount of depletion based on fair market value as of March 1, 1913 or within thirty days of the discovery of a well. An extract from the Regulations reads as follows:

"Regulations 45, article 844 (2)*** Where depletion is computed on the value as of March 1, 1913 or any subsequent date, the proportion of *** depletion representing the realization of appreciation at March 1, 1913, or any subsequent date may, if undistributed and used or employed in the business, be treated as surplus, and included in the computation of invested capital."

The portion of the depletion on valuation considered to be realized appreciation is that amount which is in excess of the depletion if based on cost. In the statement of invested capital and the camparative balance sheet to follow, the total depletion between March 1, 1913 and Dec. 31, 1917 is $660,00 or $300.000 on cost, the $360,000 being excess of depletion on value over the cost, which is realized appreciation.

OIL

Areal Unit of Depletion.—Since the demands of royalty payments on oil necessitates the determination of the amount of production for each lease, it is advisable to compute depletion by leases. In fact, for the purpose of Federal taxation this is a requisite. If there are tanks for individual wells, then depletion by such small areal units might be better, especially on large tracts or in regions of "spotted" sand conditions.

Depletion Computations.—Before calculation of depletion can be begun the following data should be known for each tract or lease, or whatever smaller unit is used:

1. If for company records:

a—Original investment returnable.

b—Annual additions to investment returnable.

c—Future production reserves.

d—Production for the year.

2. Depletion for the Federal taxation deduction.

a, b, c, and d as in 1.

e—Valuation as of March 1, 1913 for properties acquired prior to that date.

f—Valuation for discovery wells as allowed under the regulations.

g—Net income exclusive of depletion on the discovery properties.

The reserves as of any past data are the future reserves of the present day augmented by the amount of production to the past data.

The table for calculating depletion as given in Questionnaire, Form O,[1] is an excellent one and covers all contingencies.

The accompanying table is taken from one of the forms:

Years ....

(a) Estimated quantity of recoverable crude oil in ground at beginning of year, in barrels....................

(b) Production for year, in barrels ....

(c) Capital investment at beginning of year, (*cost of oil reserves plus total development costs to beginning of year (d) minus total sustained depletion to beginning of year (g)*)........................

(d) Development costs added during the year, exclusive of casing, other equipment, and amounts charged to expense.................

(e) Total capital invested subject to depletion (*c*) *plus* (*d*) ....

(f) Unit cost of recoverable oil based upon capital invested (*c*) *divided by* (*a*)..........

(g) Depletion of capital invested sustained during the year (*f*) *multiplied by* (*b*)...........................

(h)[1] Capital sum at beginning of year (*value of oil reserves at Mar. 1, 1913, or cost acquired subsequently, plus total adjustments for revaluation to beginning of year (i) plus total development costs to beginning of year (d), minus total sustained depletion to beginning of year (l)*).......................

(i) Adjustments added on account of discovery during year ....

(j) Capital sum subject to depletion (*h*) *plus* (*d*) *plus* (*i*) ....

(k) Unit cost of recoverable product, based upon capital sum (*j*) *divided by* (*a*) ....

(l) Depletion of capital sum sustained during year, and deductible from gross income (*k*) *multiplied by* (*b*) ....

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[1]Bureau of Internal Revenue, Questionnaire to Oil and Gas Companies.

[1]Plus total development costs to beginning of year, should read plus total development costs since March 1, 1913 or date of first discovery.

GAS

Areal Unit of Depletion.—Gas well rentals are nearly always fixed rates rather than royalties. Furthermore, gas production in the field is determined by a calculation from tests and seldom by meters. Thus many wells need to be combined to get a fair, average correction factor.

Since the handicaps in depletion by property units are many, and the impracticability thereof is recognized, a larger areal depletion unit is generally used and permitted by the Treasury Department. If averages are required, the pool gives the most satisfactory results. It is likely to cover conditions of similar production decline and other field elements. Where the producing area is not laterally divisible into pools, geographical divisions approximating pool sizes will do. These are districts, townships or boroughs or sections or by whatever title a county division may be designated. If conditions show similarity for areas as large as a county, or even a state, to use a smaller division is merely to duplicate work. Due to lack of well records, some companies may even be forced to consider all the developed leases as one depletion unit and disregard pool or property divisions.

Data for Depletion Computations.—The information required before beginning these calculations is mentioned under the section of Oil. The one variation is in the areal unit of data. In this case the invested capital, capital sum, with additions to both of them, and the production of reserves, are mostly by pools or geographical divisions larger than a lease.

Computation of Depletion on Units of Production.—The computations are generally carried out in tabular form. Any table should provide for changes in reserves, invested capital or capital sum thru additions or subtractions and also a determination of realized appreciation, if for Federal taxation. Following is a table suggested in the Oil and Gas Questionnaire issued by the Bureau of Internal Revenue, but expanded to cover situation of pool depletion for gas:

DEPLETION COMPUTATIONS

State____________ County____________ Pool or Geographical Division____________

	1917	1918	1919
1—Estimated recoverable units in ground at beginning of year, M. cu. ft.	11,063,015	13,640,526	11,872,992
2—Recoverable units added during year, M. cu. ft.	3,837,141	....	....
3—Recoverable units subtracted during year, M. cu. ft......................	....	....	....
4—Total estimated units recoverable during year, M. cu. ft. (1 plus 2 minus 3)	14,900,156	13,640,526	11,882,992
5—Production for year, M. cu. ft........	1,259,600	1,757,534	1,356,111
6—Capital invested at beginning of year..	....	....	1,063.12
7—Additions to capital invested returnable thru depletion during year.......	....	....	....
8—Withdrawals during year prior from capital invested returnable thru depletion	....	....	....
9—Total invested capital subject to depletion (6 plus 7 minus 8)...............	....	....	1,063.12
10—Unit cost of recoverable gas on invested capital (9 divided by 4)...........	....	....	(.0000894)
11—Depletion of capital investment sustained during year (10 times 5)......	....	....	121.24
For Federal Taxation—			
12—Capital sum at beginning of year.....	$ 769,576.59	$1,050,610.02	$ 941,636.67
13—Adjustments on account of discovery during year	378,024.94	29,871.84	....
14—Adjustments on account of withdrawals from capital sum during year prior	....	....	....
15—Capital sum subject to depletion (12 plus 13 minus 14 plus 7 minus 8).....	1,147,601.53	1,080,481.86	942,699.79
16—Unit cost recoverable gas based on capital sum (15 divided by 4)............	.077	.079	.079
17—Depletion of capital sum sustained during year (16 times 5)..............	96,991.51	138,845.19	107,132.27
18—Amount of depletion allowable as deduction from gross income...........	....	138,845.19	107,132.77
19—Realized appreciation (18 minus 11)..	....	138,845.19	107,011.53

Since by the Federal taxation regulations, the holdings in fee and those under lease are treated differently in 1917, the proper separation of the two classes should be made for that year. Instead of using reserves and the capital withdrawn the previous year, in the case of properties sold or disposed of, to get the depletion on these tracts for that year, the reserves, capital invested, and capital sum remaining at the time of disposal can be subtracted in the taxable year. By this procedure the amount of production, the depletion on invested capital and the capital sum for the year are left in the totals, and therefore automatically result in the necessary deductions.

Computation of Depletion on Decline in Closed Pressure.—This method of allowing depletion has been discussed in part in the chapter on estimation of future yield. The formula suggested by the Bureau of Internal Revenue takes depletion as a percentage of the decline in closed pressure of all gas wells during the year to the pressure at the beginning of the year plus initial pressures of new wells. The formula is founded on the assumption that the same amount of production is recovered for each pound of decline. This is now known to be incorrect. Furthermore, there is no provision for undrilled wells on any properties and consequently all depletion is taken on the producing wells alone. A correct formulae showing computations by the method is:

Capital sum to end of tax year \$10,000. Sum of pressure at beginning of year—5000 lb. plus sum of pressures of new wells drilled during year, 3000 lb. less sum of pressure at time of expected abandonment of all wells, 1000 lb.=7000 lb.

× Sum of pressures at beginning of year, 5000 lb. plus sum of pressures of new wells, 200 lb. less sum of pressures at end of tax year, 5000 lb.=200 lb.

=\$285.71.

The latter formlua makes allowance in the computation of unit cost for new wells drilled and for undrilled locations. In the first case 50% depletion is taken when the properties indicate a sum of pressures equivalent to that at the beginning of the year.

The "Oil and Gas Manual" gives a table to use for computations of closed pressure decline depletion as follows: Years ....

(a) Average closed pressure at beginning of year less estimated average closed pressure at time of abandonment.

(b) Decline in average closed pressure during year.

(c) Capital invested at beginning of year (*cost of gas reserves plus total development costs to beginning of year (d) minus total depletion to beginning of year (g)*.

(d) Development costs added during year, exclusive of casing, other equipment, and amounts charged to expense.

(e) Total invested capital subject to depletion (*c plus d*).

(f) Unit cost based upon capital invested (*c divided by a*).

(g) Depletion of capital invested sustained during year (*f multiplied by b*).

(h) Capital sum at beginning of year (*value of gas reserves at March* 1, 1913, *or cost if acquired subsequently, plus total adjustments for revaluation to beginning of year (d) minus total sustained depletion to beginning of year*. [1]).

(i) Adjustments added on account of discovery during year.

(j) Capital sum subject to depletion at end of year (*h plus d plus i*).

(k) Unit cost based upon capital sum (*j divided by a*).

This table fails to include in (a) the closed pressure of new wells completed during the year and the closed pressure of undrilled wells less their abandonment pressures. In other words, on partly developed tracts, the depletion is being taken on the producing wells irrespective of the size of the tract and the possibility of more wells thereon. The withdrawal of reserves and costs or values cannot be taken care of in this table.

Depletion by Percentage Decline.—The method of application in the case of gas is similar to that for oil except that percentages are obtained in relation to production for the year in M. cu. ft. or loss in pounds closed pressure. The method given in paragraph above is one of percentage decline.

[1]Depletion of capital sum sus'ained during the year and deductible from gross income (*k multiplied by b*).

Appraisal Of Oil And Gas Properties

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CHAPTER XX

COMPUTATION OF DEPRECIATION

Oil or Gas

Definition of Depreciation

DEPRECIATION is the decrease in the worth of a property through wear and tear, inadequacy or obsolescence. The term covers more than mere wear and tear, for machinery and other equipment is often replaced by a newer and more advanced type, even though the original has not yet outlived its usefulness. The rate of depreciation depends upon the peculiarities of each individual case. Repairs of parts may be made when required, with the result that the life of the property is materially extended. Provision in the accounts for this annual lessening in worth of the physical property, either through wear or tear, inadequacy or other cause, is the annual depreciation.

Depreciaticn and Rate of Production Decline and Efficiency.—There is certain equipment necessary in the industry, the usefulness of which decreases with the decline in production, such as well equipment. On the other hand, there are other types of equipment which decrease in usefulness more rapidly in the later life. From the diagram it is evident that the greatest returns when depreciation is based on ultimate production, are made in the early life of a well. The principal usefulness of the casing, tubing etc., is in the first few years. Thus, when over 90% of the oil or gas has been exhausted, only about 26% of the depreciation has been written off when depreciation is taken by the straight line method. This introduces the large risk of recovering the remainder of the investment in the years of low production. In the case of the gas engine, its greatest efficiency is in the first eight years, while in the next four, assuming a twelve year life, it decreases to eventual uselessness. However, this is a probelm of replacement at the end of the life of a well and is best accomplished by the straight line or other recognized method of charging depreciation. The well equipment need not be replaced at the end of the life of the well but it is essential that investment be returned.

Causes of Depreciation

1—*Normal Wear.*—Depreciation on equipment is an ever present and constant process. Certainly the inevitable state of final discard because of uselessness can be delayed by careful maintenance, but no amount of attention will ever prevent its finally reaching such an end. Only certain equipment completely wears out. Well tubing is sometimes pulled for the purpose of safety and is then used as gathering lines. The maintenance of some property becomes too costly and it is more economical to replace it than to endeaver to obtain the full use thereof. The reason for replacement may thus be due to the commercial advantage to be derived rather than to complete uselessness.

2—*Inadequacy.*—The increased demands of service or the change of the source of supply may cause an article to be uneconomical for further operation. This is common in oil or gas fields where, through depletion, the bulk of the supply shifts from place to place. A pipe line adequate to handle the production one time, may be inadequate a short time later. Rather than increase the number of lines, it is often a better policy to remove the smaller line and replace it with one of adequate diameter.

3—*Obsolescence.*—This form of depreciation arises from the innovation of some new kind or type of article which would so increase efficiency as to warrant the discontinuance of a former article, even though it were far from worn out. This is not important in oil and gas equipment except as to specialized drilling tools and facilities in connection with new processes or innovations. The latter is illustrated by obsolescence of some early machinery installed in compressor gasoline plants, which has, in some cases, now become obsolete through the development of the absorption process of casing-head gasoline recovery.

4—*Physical Deterioration.* — Although physical decay is closely allied to depreciation by wear and tear, there is a distinction. Deterioration goes on in well equipment, derricks, pipe lines and other physical property exposed to the elements, irrespective of whether it is used or not. The decay may be hastened, in some instances by excessively cold weather and the consequent freezing of the condensation in the gas lines, or by the exterior pressure of frozen masses, thus weakening the connections.

5—*Accidents, elements and negligence*—Some losses or necessary replacements may be attributed to accidents, others to the inevitable effect of the elements or through negligence. Fire, lightning, wind, and flood are other sources of destruction. The loss incident to the action of the elements may not be the only material uninsured loss, but the indirect loss due to discontinuance of service or excessive repair cost when handicapped by unusual weather or other conditions.

6—*Deferred Maintenance.*—Failure on the part of an individual or corporation to provide for necessary repairs permits a property to depreciate at a more rapid rate than was assumed under conditions previously described, in which a normal amount of repair was taken for granted. The negligence may be avoidable or unavoidable. Inefficient operation can be avoided, but finances necessary for repair work can not always be secured, especially in times of economic depression, when the income hardly covers the operating expenses.

7—*Other Sources of Depreciation.*—Transportation and distribution systems suffer from still another source of damage, such as electrolysis, insects and the like. but these need not be discussed, since our concern is with the production system.

Methods for Computing Depreciation.—There are many methods for computing depreciation in use. Some are practised by the accountants, while others because of their extreme complexity are limited to the appraisal engineer.

Some of the methods are:

1—Straight line.
2—Decreasing percentage.
3—Sinking fund.
4—Reducing balance.
5—Increasing balance.
6—Annuity.
7—Equal annual payment.
8—Gross revenue basis.
9—Unit cost.
10—Depletion rate.

Straight Line Method.—This method has been observed in most common use by oil and gas companies. It is based on the assumption of a uniform and constant reduction in the value of a property. It involves no computation of interest accretions as do some of the following methods, and is, by this lack of complexity, the most easily understood.

The amount to be set aside each year, where no salvage is considered, is obtained by dividing 100 by the number of years of life anticipated for the article or class of property. Knowing the investment and the life of the property,

let i represent investment, and the life in years, (or other units of time) then

$$\text{the annual charge} = \frac{i}{n}$$

If salvage is a factor, then let s be the expected salvage value and:

$$\text{Annual charge} = \frac{i - s}{n}$$

Substituting for i, $200., for s, $40., and for n, 10 yrs., we have:

$$\text{Annual charge} = \frac{\$200 - \$40}{10} = \$16$$

The investment would be reduced annually by $16 and the amount added to the reserve for depreciation. The following table illustrates the procedure:

Age in yrs.	*Investment remaining at the end of each year*	*Depreciation during the year*	*Reserve for depreciation at the end of each year*
0	$200	$	$
1	184	16	16
2	168	16	32
3	152	16	48
4	136	16	64
5	120	16	80
6	104	16	96
7	88	16	112
8	72	16	128
9	56	16	144
10	40	16	160
		Salvage	40
		Original Investment	$200

Salvage value plus depreciation reserve = Original investment.

If using a graphic representation of the value remaining at the end of each year, the undepreciated balance at the end of any year can be read vertically above the age point.

For the benefit of firm accountants, and also to facilitate estimation of the depreciation of equipment, curves based on the size of wells and their remaining life can be drawn for each pool, property or other divisional unit. One can be readily constructed from the composite decline curve by finding the remaining life of assumed wells of various sizes and plotting the results to form the basis for the curve[1].

Decreasing Percentage Method.—This method is based on the "Straight Line Method," with modifications to provide for additions or withdrawals. Its most common use is found where an addition or withdrawal does not change the life of the property. The addition, if such, because of the nature of the property, takes a life equivalent to the remaining life of the original investment. This is commonly the case of additions to well equipment, where the life of the production establishes the life of the physical property. Of course, the later replacements if removable may have a salvage value.

The use of these uniformly changing percentages with the investment reduced by previous depreciation charges, should, if no additions or withdrawals are made, give the same amount of annual depreciation as the "Straight Line Method."

Sinking Fund Method.—The "Sinking Fund Method" of calculating depreciation is based on the assumption that a uniform amount is placed aside each year and improved by interest at a certain rate. Because of the interest increments, a lesser amount may be placed in the depreciation reserve each year, than by the straight line method. The building up of interest is theoretical, as is the depreciation reserve. The amount calculated as replacement does not go into an actual fund to restore capital but remains in the business and consequently earns interest at a rate commensurate with that of other investments. Irrespective of this fact, the fund should be treated as though an actuality and interest should be allowed at a rate common to securities. In any event, the reserve should be accounted for.

The increasing of the fund takes place by geometrical progression. Fixed annual charges plus their respective interest accumulations at the end of each period or unit of time are accounted for. On a property with a twenty year life, the capital returned for the first year will be increased by compound interest for nineteen years, the second for eighteen years and so on. The amount for the twentieth year, coming when the replacement should occur, receives no interest. The sum to set aside each year must be determined by computation.

The general formula for progression of this kind may be derived by calling r the constant factor and the number of years:

$$x + xr + xr^2 + xr^3 + xr^{n-2} + xr^{rn-1}$$

The sum of these amounts equal the investment after the term of years established as the life of the property. Let i be the investment to be returned, n the years of life, and x the fixed annual amount being improved at r rate of interest. By solution the formula becomes:

$$x = i \frac{(r-1)}{(r^n - 1)}$$

Substituting in the equation $1,000 for i, 4½% for r, and 10 years for n, we have:

$$x = \$1{,}000 \; \frac{1.045-1}{1.045-1} = 81.3788+ \text{ or } \$81.38$$

This amount set aside annually for ten years at 4½% compound interest will equal $1,000.

A table in the appendix shows the amount necessary to replace $1 for a varying number of years and at several percentages. Since payments are made monthly for oil or gas it is possible that some may desire even greater refinement in the calculations. For these, a table showing a replacement fund for payments being made quarterly, semi-annually or annually has been arranged.

Reducing Balance Method. — This method is based on the assumption that the rapidity of depreciation decreases with age. By this method a lesser amount is set aside each successive year. The dominant feature is the extreme conservation of the method. Since the depreciation decreases with age of the article, the bulk of the cost is returned in the early life, and failure to recover cost is less probable than by the straight line method. On the other hand the burden of depreciation may come when the plant is not capable of bearing such charges.

The theory of the method is to charge off a changing percentage on the investment. The percentage adopted must be calculated, so that at the end of the assumed life the investment less salvage has been written off.

The amounts set aside each year may be increased by interest, as in the case of the sinking fund method. In this event a still smaller amount than indicated by the simpler method needs to be set aside. It will necessarily be determined by a combination of the two methods.

Increasing Balance Method.—This is opposite to the decreasing balance method. The annual amount set aside is increased rather than reduced. The procedure for finding the required amount is similar to that used in the reducing balance method except that the results would be interchanged. That is, the amount for the last year in the previous case would be that for the first year in this case, and the same interchange for each of the other years respectively. Its advantage lies in placing a greater depreciation burden on the later life, for plants that are less capable of bearing the depreciation burden in the early life. However, it is not adapable for use in the oil or gas industry because of the high risks in the later life.

Annuity Method.[1]—The principle of

[1]Suggested by similar diagram, M. L. Requa Methods of Valuing Oil-Lands, Bull., A. I. M. E., Feb., 1918.

[1]Saliers, E. A., Principles of Depreciation, pp. 152-157.

this method is based on the assumption that interest on the remaining investment should be compensated for in the reserves. Furthermore, the annual allowances should be equal when the rate of interest on the investment is the same as assumed for the sinking fund.

The deduction for depreciation is determined by finding a sum which, if deducted each year from the remaining investment, plus interest thereon, will reduce the investment to zero or salvage. By this procedure, the full amount of interest at a given rate on the investment is returned in addition to the investment.

Depreciation is a function of the rate of interest on the investment and not upon the rate by which the sinking fund accumulates as in the equal annual payment method. The interest for the first year is on the original investment, for the second year on the original investment, reduced by the amount that the total annual allowance for interest and depreciation is in excess of the interest on investment for the first year.

Equal Annual Payment Method.—This method is in many respects similar to the annuity method described. The theory is to deduct from earnings each year a uniform charge which will include depreciation on the remaining investment and the interest cost accruing to that investment. The interest is computed at the assumed rate on the continually decreasing investment. Interest will gradually decrease with the reducing investment and consequently the depreciation increases, since the the sum of the two is a fixed annual amount.

Gross Revenue Basis Method.—This bears a similarity to the depletion rate method except that instead of being based on the production it is based on the gross income. Gross income will, of course, be controlled by the production but fluctuates, often violently, due to the changing sale price of the commodity. The principle of the method is to deduct a fixed percentage of the gross revenue. The method, however, may have no relation to the decline in investment through deterioration, as it is distinct from invested capital, unless revenue is based on a fixed percentage of invested capital.

Unit Cost Method.—This method is not practicable for oil or gas companies and is mainly adapted to depreciation in industrial plants. Therefore the method will not be described here.

Insurance Method.—This is not really a method of depreciation but a principle on which depreciation is provided for. The method is applicable to a gas company only when it serves as a public utility. The name of the method developed from the fact that it involves the actuarial principles employed in insurance. No depreciation reserve is built up for the eventual replacement of a certain property, but the amount of depreciation incident to a property in any one year is invested during that year in the replacement of equipment, not necessarily the equipment on which the depreciation has been taken. This happens to be the usual bookkeeping procedure in most companies.

Depletion Rate Method.—This method may be too refined to use with certain appraisals. For accounting, especially the accounting of well equipment, the principle involved in this method is perhaps the fairest, and if a prior determination of reserves for depletion is made, it is easy to apply. The principle is to depreciate equipment at the depletion rate of the well or group of wells. The investment is divided by the ultimate reserves as of date of the investment, and the resulting unit cost is multiplied by the production in barrels or M cu. ft., for the year. Let i be the investment, v the ultimate reserves in barrels or M. cu. ft., x the unit cost per barrel or M. cu. ft., and p the production in barrels or M. cu. ft. The equation is:—

$$\frac{i}{v} = x$$

and x times p = Depreciation.

By this method depreciation is charged commensurate with the decline in production. Since the income is from production, it is easier for a company to meet the returns in the investment during the early years when the property is most productive. Small production, or that at the end of the life of a well is seldom sufficient to pay for depreciation and depletion on the straight line basis.

The method does not recognize actual deterioration as such and therefore is not satisfactory for appraisals under certain conditions. For instance, a new field with many wells drilled in the past year or two, would, if a life of ten years was assumed, have a reproductive value of its equipment equivalent to about four-fifths of its cost by the straight line method. On the other hand, by the depletion rate, the reproductive value would be more nearly one-third of the cost. In cases of valuation for purchase, sale or rate making, the former procedure would be more accurate while for accounting the latter would insure against risk and unprofitable operations at the state of small production.

Pipe lines, transmission and distribution lines, have a more or less permanent life, irrespective of the field production, by virtue of the possibility of substituting for the diminished natural supply the artificial product.

Conclusions.—The choice of the method for determining the amount of depreciation depends upon the circumstances surrounding each case and the degree of accuracy that is desired. There are various combinations of the methods described that can be applied. The records available are often quite inadequate for a required appraisal, and again the time allowed is too short to accomplish the work. For accounting, the more theoretical methods involving interest are impracticable at least for many companies.

Depreciation Percentages by the Straight Line Method.—Following is a selective list of depreciation percentages suggested for Oil and Gas equipment, by the Bureau of Internal Revenue in the Oil and Gas Manual

Class A, No. 1—Drilling Equipment

This includes engines, boilers, rig irons and portable derricks.

It is recommended that four years of life be allowed to equipment as a whole, depreciated at the following rate:

	Percent
First year	40
Second year	25
Third year	15
Fourth year	10
	90
Salvage	10
	100

Permanent derricks, rig irons, boilers, and engines left at the well are included under "Well equipment."

Drilling tools (cable and rotary), and fishing tools are included under "Tools."—Class A, No. 5.

Class A, No. 2—Well Equipment

As most equipment of a producing well has no separate value apart from the well, it is suggested that all wells and their equipment be depreciated at the same rate as the wells are depleted, using the same curve rate for both; but if the life of the physical equipment is greater than the life of the deposit, then the depreciation rate of the physical equipment will be governed by the reasonable expectation of the life of the deposit.

If the life of the equipment is shorter than the life of the well, then replaced equipment should be charged against maintenance and operation.

This method proved satisfactory in the appraisements of the Independent Oil Producers Agency of California, embracing some 130 companies, and is generally acceptable to all operators who have been consulted in the matter.

Class A, No. 3—Dehydrators

These are either of electric, pipe or tank type. The life of the pipe and tank dehydrators is very erratic as these burn out quickly with practically no salvage. It is recommended that this type of equipment have a straight line depreciation as follows:

	Life Years	*Depreciation per annum Percent*
Electric	5	20
Pipe	2	50
Tank	2	50

Class A, No. 4—Tanks

The following depreciation rate for tanks is recommended:

	Life Years	Percent
Steel, 5000 to 55,000 bbls.	20	5
Steel, 2500 to 5000 bbls..	12	8⅓
G. I., 500 to 2500 bbls....	12	8⅓
G. I., less than 500 bbls.	8	12½
Wood	5	20
Movable tanks—		
G. I., 500 to 2500 bbls.	9	11$^{1}/_{9}$
G. I., less than 500 bbls.	6	16⅔
G. I., water tanks, 500 to 2500 bbls.	8	12½
G. I., water tanks, less than 500 bbls.	5	20

These results may be used for all classes of service—that is, oil producing, refineries, etc.

Class A, No. 5—Tools

This includes Standard, rotary, and fishing tools. While rotary equipment may be shorter lived, it is, in general, offset by the Standard tool equipment which will have a life of at least four years in many cases.

Owing to the excessive wear and tear and losses on such equipment an average life of three years is recommended, using an annual depreciation rate of 33⅓ percent.

Class A, No. 6—Transportation Equipment

All transportation equipment, such as motor trucks, autos, wagons, horses, and harness, can be placed at a three year life or an annual depreciation rate of 33⅓ percent.

In fact, the average life of automobiles is less than three years. The percentages of cost for horses, harness, and wagons is such that they can be grouped with three years' life, disregarding salvage value.

Class A, No. 7—Water Plants

Considering the water well, pump, steam power, gas and oil power and electric power as a class, they may be given a useful life of approximately 10 years, allowing a straight depreciation rate of 10 percent.

Class A, No. 8—Electric Equipment

In considering electric equipment, one may include the separate items of generators, motors of various sizes, transformers, wiring (both indoor and outdoor), power lines, and switchboard.

As oil-well motors are not suitable for other uses and as the class of wiring usually done on leases is not up to utility company standards, it is recommended that a combined life on electric equipment be placed at 10 years, allowing a depreciation rate of 10 percent.

Class A, No. 9—Machine Shop.

In covering machine shop there is included wood buildings, power tools, blacksmith tools, small hand tools, shafting, and shop power, which will, on an average, have a seven year life or a depreciation rate of 142/7 percent. The smaller hand tools, of course, may have a life of not more than two years, but their cost is not important and the depreciation rate is lowered by the longer life of more expensive items, such as power, tools, wood buildings, shafting, and power equipment.

Class A, No. 10—Buildings

Buildings are grouped into four general classes:

No. 1—Wood, which includes small dwellings, small outhouses, small warehouses, small power plants, and small platforms which are built on the ground. These have an average life of 10 years, which allows a depreciation rate of 10 percent.

No. 2—Frame buildings, placed on brick or concrete foundation, with siding and shingle or patent roof painted, have an average life of 15 years or a straight line depreciation rate of 6⅔ percent.

No. 3—Corrugated iron siding, renewable, has a life of six years or a depreciation rate of 16⅔ percent.

No. 4—Concrete, brick, and steel frame have an average life of 25 years or an annual depreciation rate of 4 percent.

The permanent buildings may outlast the remainder of the plant, hence have no salvage value. Gulf Coast fields may claim shorter life for iron buildings because of salt air conditions.

Class B—Pipe Lines

Pipe lines are subdivided into main lines, pump stations (which include all equipment such as engines, pumps, boilers, etc.), auxiliary equipment, buildings, telephone and telegraph, and terminal facilities.

It is recommended that—

Mains 6 inches or over in diameter be based on a 20-year life or an annual depreciation rate of 5 percent.

Mains under 6 inches diameter be based on a 16-year life or an annual depreciation rate of 6¼ percent.

Gathering lines be based on a 10-year life or an annual depreciation rate of 10 percent, with a salvage of 10 percent.

Pump stations, including all equipment, telephone lines, and terminal facilities based on a life of 10 years or an annual depreciation rate of 10 percent.

These conclusions were reached after carefully considering detailed data in which it was decided that pipe lines could be grouped into the subdivisions given above.

The subject of electrolysis in pipe lines has been investigated and the losses have proved to be very small and negligible in comparison with the amounts invested, so far as making any special allowance in depreciation.

Class E—Natural Gas—Utility Companies

The drilling equipment and well equipment of natural-gas companies should be depreciated at the same rate as drilling equipment and well equipment for oil wells, previously given.

The following depreciation rates are suggested for gas pipe lines:

	Percent
Mains	8$^{1}/_{3}$
Gathering lines	10
City lines	10
Compressor stations, including gas compressors, engines, boilers and boiler equipment, should be grouped into one heading and depreciated at an annual rate of	14$^{2}/_{7}$
Gathering stations	16$^{2}/_{3}$
Field stations	25
Meters and regulators	20

The information at hand in which the cost of the equipment was taken into account showed that a natural-gas plant could be depreciated, as a whole, at a rate of 10 percent. It is a general consensus of opinion that the average life would not be over 10 years.

It is recommended that conditions existing on January 1, 1916, be used as a basis, and that all expenses incurred to maintain the output or carrying capacity of lines, as of that date, be treated as follows:

That intangible expenses may be charged direct to maintenance as an operating expense.

The tangible items be charged to investment or capital account and should be given a 25 percent salvage value and the remaining 75 percent charged off at the rate of 17½ percent per annum for all gas properties other than those in West Virginia, Pennsylvania, and possibly Ohio, where the natural-gas plants, as a whole, should be given a 15-year life, and the extensions figured on a 7-year life on a 15 percent salvage and the remainder charged off at the rate of 12 percent per annum.

The above conclusions are based upon a 7-year life for gas fields in West Virginia, Pennsylvania, and possibly certain portions of Ohio, and on a 4-year life for all other gas fields.

The shorter life for the other gas fields can be substantiated by numerous examples, such as southern Kansas, Hogshooter, Cushing and Pawhuska fields, all of which were large producers and were all practically exhausted within five years, but the bulk of the gas was taken out during the first three years.

Class F—Natural-Gas Gasoline Plants

Compression plants may be divided into compressors, engine boilers, auxiliary equipment, cooling equipment, gathering and distributing lines, blending tanks, buildings, and electrical equipment.

For absorption plants, separate items of absorbers, stills, condensors, cooling equipment, auxiliary equipment, boilers, engines, electrical equipment, tanks, and loading racks may be considered.

On the whole the average life of these plants is not over five or six years.

In consideration of these data and other data at hand, it is recommended that:

The original cost be placed on a 20 percent salvage, and the remaining 80 percent be depreciated on the basis of 6 to 10 years' usefulness of the plant,

or on the actual known life of wells producing gas.

Summary

			Useful life Years	Annual depreciation Percent
A	1	Drilling equipment	4	40-25-15-10
	2	Wells		
	3	Dehydrators:		
		Electric	5	20
		Pipe and tanks	2	50
	4	Tanks:		
		Steel 5000 55,000 bbl. ..	20	5
		2500-5000	12	$8\frac{1}{3}$
		Galvanized iron 500-2500.	12	$8\frac{1}{3}$
		Less than 500	8	$12\frac{1}{2}$
		Wood	5	20
		For movable tanks:		
		Galvanized iron 500-2500.	9	$11\frac{1}{9}$
		Less than 500	6	$16\frac{2}{3}$
		For water tanks:		
		500-2500	8	$12\frac{1}{2}$
		Less than 500	5	20
	5	Tools	3	$33\frac{1}{3}$
	6	Transportation equipment	3	$33\frac{1}{3}$
	7	Water plants	10	10
	8	Electric Equipment	10	10
	9	Machine shops	7	$14\frac{2}{7}$
	10	Buildings:		
		Small wood	10	10
		Frame structure	15	$6\frac{2}{3}$
		Corrugated iron siding ..	6	$16\frac{2}{3}$
		Concrete	25	4
		Brick	25	4
		Steel	25	4
B	1	Pipe lines; less 10 percent salvage:		
		Mains over 6 in. diam...	20	$4\frac{1}{2}$
		Mains under 6 in. diam..	16	$5\frac{5}{9}$
		Gathering lines	10	9
		Pump Stations	10	10
		Tank cars	20	5
C	1	Refineries:		
		Class 1—located at points assuring a long supply of crude oil; or well-constructed plants	20	5
		Class 2—located at points assuring supply of crude oil for several years. ...	10	10
		Class 3—Skimming plants and small refineries of poor construction, or located at points where the supply of crude oil is not assured for a long period of time.	6	$16\frac{2}{3}$
D	1	Sales or marketing equipment:		
		Tankers	20	5
		Barges	5	20.
		Filling stations:		
		Class A—Ordinary wood or corrugated steel construction	5	20
		Class B—Brick and concrete or extraordinary construction	10	10
		Distributing stations	10	10
		Tank wagons:		
		Motor	4	25
		Horse	6	$16\frac{2}{3}$
		Steel barrels	7	$14\frac{2}{7}$
		Track switches	8	$12\frac{1}{2}$
E		Natural gas (utility companies):		
	1	Drilling equipment (see A-1)		
	2	Wells. (See A-2)		
	3	Gas pipe lines:		
		Mains	12	$8\frac{1}{2}$
		Gathering lines	10	10
		City lines	10	10
	4	Compressor stations	7	$14\frac{3}{4}$
	5	Gathering stations	6	$15\frac{2}{3}$
	6	Field stations	4	25
	7	Meters and regulators	5	20
		Considered as a whole plant	10	20
F	1	Natural-gas gasoline:		
		Plant—Compression, with 20 percent salvage value	6-10	$13\frac{1}{3}$ to 8
		Absorption plants, with 20 percent salvage value	6-10	$13\frac{1}{3}$ to 8

Depreciation of Intangible Values.—The amount representing intangible value may or may not be depreciated as the circumstances vary. The engineering and labor in connection with the laying of transportation and distribution lines may be a permanent investment, as the life of these may be assumed as relatively permanent. The intangible investment, in this case is still intact, although as far as physical value is concerned, the owner has no property to show for it. However, it has been recognized that such intangible investment is proper and necessary, and may be included in the valuation. Should a time come when the company as a going concern is likely to terminate, for any reason, depreciation can be calculated and intangible value returned to the investor. For federal taxation purposes, depreciation on this class of intangible property is permitted, if its use is limited in its duration, as for example, patents, copyrights, licenses and franchises. To claim deduction it is necessary to estimate the length of time that the intangible asset is to be in use. Good will does not normally depreciate in an enterprising company, but rather increases in value with the expansion of the business. As has been previously stated, no good will exists where a company enjoys a monopoly and is free from competition. It is hardly probable that any depreciation of good will can occur under the present market conditions that surround natural gas companies.

Summary of Kinds of Depreciation

- **I Tangible or physical property**
  - 1.—Normal deterioration
  - 2.—Deferred maintenance
  - 3.—Diminution of supply
  - 4.—Inadequacy and obsolesence
  - 5.—Contingent
    - (a) Accidents
      - Negligence
      - Elements
        - Fire
        - Wind
        - Water
        - Weather
        - Lightning
    - (b) Other Damages
      - Animals
      - Insects
      - Electrolysis
- **II Intangible property**
  - 1.—Services on physical plant.
  - 2.—Franchises and licenses
    - (a) limited in time
    - (b) perpetual
  - 3.—Good wil.

Appraisal Of Oil And Gas Properties

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Chapter XXI.

THE GENERAL REPORT

Oil or Gas

Purpose

AN important matter, frequently over looked is the detail and appearance of the final report. A board of corporation directors usually requires a report on valuation to be brief, concise and logically summarized. On the other hand, a rate making commission, or other board of examiners, wants information as to how each step was determined and full substantiation of the fundamental conclusions. Obviously the amount of detail depends upon the purpose of the valuation. An appraisal for a claim of rate increase is essentially different from one to be used as the basis of a business transaction. Appraisals for federal taxation claims must show more detail than those to be submitted to company officials only. The government cannot accept conclusions without fact, merely on the basis of the recognized ability of the appraiser. Company officials, on the other hand, are often satisfied with a statement of a few words, trusting to the efficiency of their appraiser for the reliabilty of the results.

Arrangement of Detail.—Where the appraiser is a disinterested party, and the report demands full details, the arrangement of the information to facilitate checking and examination becomes an important element. The appearance adds to the possibility of a successful presentation. The grouping of particular classes of data is not always the most satisfactory. Primarily, the data sheets should be planned at the beginning of the task with a view to their inclusion, if necessary, in the final report. Where a number of diversified computations are made on separate sheets, all leading up to conclusions in a certain operation, and the conclusions of these operations develop into the summary, it is essential that proper forms and a comprehensive system be used. For instance, a large oil company controls many properties in various pools, and the value at each property depends upon the amount and quality of the production and the age of the individual wells thereon. Here the proper arrangement of data sheets requires much attention and preparation in order to intelligently and expeditiously obtain the results. Production data, well records, and other facts establish the value of the well. Three distinct tables or forms for each of the classifications mentioned are desirable. The question arises as to whether all the tabular forms of one kind be bound together or whether the property be the determining factor in the arrangement. Certainly, if the examiner, to check results, must refer most to the production and well data, then these data should be placed where most convenient and logical. Too much detail obscures the clearness. A compromise between too little and too much must be reached. Arrangement and detail are important distinctions of an appraiser's ability.

Summary of Results. — Frequently the description of conclusions or tables of results are most effective when placed at the beginning of the report. It serves the purpose of giving the reader a mental picture of the whole which he can or cannot later substantiate to his own satisfaction by subsequent analysis of the details. Furthermore, many officials or clients desire only the summary of results and prefer to leave the study of the details to assistants or advisors. This should not preclude the placing of conclusions in their logical position at the end of the report, either in greater detail or in a different arrangement to give a new picture of the results.

Working Data.—It is impossible, and likewise unnecessary to file all working data. However, no computation or scrap of record should be discarded in the waste basket because a report is completed. The investigators may demand substantiation of certain points for their own satisfaction and a well kept file of working papers provides against this contingency. In the report proper, where full details of each step are irrelevant, especially where the procedure is repeated many times, the methods and computations for one or several units only should be analyzed from beginning to end.

Descriptions of Methods.—Accompanying the forms and summaries should be a general report discussing the methods adopted, with the technical and legal support of each method. Opinions vary as to the proper procedure, and no one appraiser can expect his results to be accepted without contest of some point or other. Consequently, a full, clear and concise record of every fundamental principle and every method, whether usual or unusual, should be given. Failure to properly analyze the full procedure, where the purpose of the report demands full explanation, is likely to be construed as an indication of inability or intent to avoid criticism.

Maps, Curves and Charts.—It is not always possible to obtain uniformity in the size of maps. Decline curves can generally be placed on sheets of the same size. Charts and diagrams may vary considerably in shape and size, and all this material is best arranged under separate cover as exhibits. Each sheet of the report should be made to conform with the general report size or folded to that size, except for very good cause.

Photostats are much more attractive than blue prints, especially where any coloring is to be done. Furthermore, large figures can be reduced to agree with other sheets. By photostating, important information from ledgers can be incorporated into the report with the least effort and with the stamp of absolute authenticity. One report was noted where the original sheets were all in long-hand and the duplicates as photostats. The company had to make several thousand photostats in the process, but the expense was much less than the labor of either typing or copying the original data.

White prints, although slightly more expensive than blue prints, can be made more legible and attractive, especially where notes are added. Compilation of well discovery maps for taxation reports can be made on white prints with least expense in proportion to the advantages derived.

Sometimes instead of a photostat or a blue print the appraiser prefers to have certain very simple maps traced on semi-transparent paper. One advantage of this is that when the map is colored on the reverse side, the color shows through sufficiently without in the least impairing the detail on the front.

Binding.—A report may be bound solid or on a loose leaf post binder. Where additions are to be made from time to time, a post binder or other type of loose leaf folder should be chosen. Solid binding is more permanent, and of course preferable, because of the appearance and the assurance that sheets can not be lost or improperly removed. In any event, the binding should be solid enough to prevent the possibility of the whole mass becoming loose, or of sheets pulling out with ordinary usage.

The cover and the back should bear a title arranged and explained in a manner clearly setting forth the contents, the company, and the region concerning which the data were compiled.

An indexed or detailed table of contents is a valuable part of the report.

Marginal indices are also a great aid for quick reference. The binders should be so planned as to allow the attachment of tab indices without their projecting beyond the edge, thus avoiding the danger of being torn off.

Summary.—The appraiser should plan the arrangement of all his material—a careful outline of the whole—in his language, before beginning the report. All necessary tables and forms ought to be determined with a view to adaptability, clearness and convenience in handling. Particular attention should be paid to verifying copies and to the appearance of the typing, binding and indices. A pleasing finish has an effect worth attaining.

CHAPER XXII

OFFICE RECORDS

Oil or Gas

Aim of Records

Many oil and gas companies have failed to appreciate the necessity of a proper accounting system. In consequence some wells are operated when their production is less than the yearly rental and maintenance cost. Furthermore, the equilibrium of assets, that is, the ratio of reserve acreage to the number of customers and the future demands for gas (Natural gas companies) is an important consideration in the guiding of future investments. Such a record can be kept with more exactness by gas companies because future demand and supply are factors more definite than for oil companies.

However, most of the larger oil companies refine and market their products thus establishing a fixed demand for which production must be maintained. Numerous other tables and graphs should be kept for the efficient operation of the company.

Table No. 2

PROPERTY LEDGER

Name of Property—John Doe Location—SE¼ SE S of 36T 21 N R 6E, Pawnee Co., Okla.
Sheet No. 231

DATA	Annual	Depletion	and	Depletable	Investment						
Annual Depletable Investments	1910	1911	1912	1913	1914	1915	1916	1917	1918	1919	1920
Bonus	100.										
Rentals		200.	200.								
Drilling cost				2,000.00							
Other Items				50.75							
Total to date	100.	300.	500.	2,550.75							
Depletion by years											
Investment beginning of yr				2,550.75	2,823.42						
Additions				483.75							
Withdrawals				None							
Total Depletable Investment				3,034.50							
Estimated future Reserves beginning of Year											
M. cu. ft. or bbls				435,310							
Unit cost				.00697							
Production for year—M. cu. ft. or Bbls				30,280							
Amount of Depletion Allowance				211.08							
Balance forwarded				2,823.42							

Article and year installed		Probable Life and percent	Original value	Annual Depreciation and Physical Investment								
1913												
Tubing and	yr.											
Casing	1923		2759.30									
Pipe	1923		72.15				108.71					
Total Depreciation							108.72					
Balance brought forward							2,831.45					
Depreciated Balance							2,722.73					
Total Capital Investment remaining at end of year							5,546.15					

Table No. 3

STATEMENT OF PROFIT AND LOSS

Operating Expenses	1910	1911	1912	1913	1914	1915	1916	1917	1918	1919	1920
Labor				515.20							
Supplies				50.11							
Water				....							
Fuel				....							
Teaming				30.20							
Repairs				72.18							
Cleaning				......							
Share of Pumping				105.00							
Royalty				200.00							
Miscellaneous				13.00							
Total				985.69							
General Expenses											
General Property				63.18							
Superintendence and Office				132.00							
Storage and Shipment				......							
Insurance and Taxes				45.52							
Miscellaneous				21.31							
Total				262.01							
Grand Total—Expenses				1,247.70							
Amount of Depletion				211.08							
Amount of Depreciation				108.72							
Gross Deduction from Income				1,567.50							
Gross Income				6,065.00							
Profit and Loss				4,488.50							
Income to date				4,488.50							
Deficit to Date											

Table No. 1

Statement of Company Operating Expense for Each Property[1]
Operating Expenses and production for month of[2] ....192....

Name of property	Labor	Supplies	Cleaning	Repairs	Share Royalty	Share Gen.expense	Misc.	Total	No. wells Prod.	Cost per Well	Prod.in M.cu. ft. or bbls.	Cost bbls.or M.cu.

(1) From Bull. 158, Pet. Tech. 43—Smith, C. G.—Cost accounting for oil producers, revised to cover Natural Gas.

(2) Columns for fuel, teaming, and water might be added.
The general expenses cover a share of the superintendence, office, taxes, insurance on property, pumping, storage and shipment, and other overhead.

Record of Future Reserves.—If production tests are made with the degree of accuracy that is essential to the calculation of reserves on individual properties, then such a record of reserves by properties should be recorded. Total future reserves on producing wells, with the probable annual rate of recovery, will aid in determining the number of wells necessary to maintain production in accordance with the demand.

Operating Costs per Well—Barrels or M cu. ft.—For the purpose of appraisal the cost of operating should be entered in the books somewhat differently than is customary. Records, especially if they are kept with all the detail practicable for valuation purposes, will greatly facilitate the making of appraisals. Table 1 is a suggested form, subject to revision to accomodate the records and requirements of each company.

This form brings together the items connected with operating expenses as used in appraisal. It serves the further purpose of informing the operator when

the well or tract becomes unprofitable. It may be that items included in general expense are usually excluded when ascertaining the time for abandonment. Some producers prefer to increase the recovery of oil or gas by relieving very small wells of the burden of overhead. Production recovered under such circumstances is not making any income, properly speaking, yet is sometimes justified. The company in any such event understands what it is doing.

Investment and Redemption of Capital.—A company should be able to tell at any time whether it is more profitable to continue to operate a property or to sell it, and on the other hand, whether a complete return of investment can be expected. Opportunities frequently arise for the disposition of leases and at such times an accurate record of the capital still invested might save a company from loss. To facilitate the determination of the remaining investment, Table No. 2 on preceeding page is suggested as a guide.

This form can be broadened to meet any detail desired by the company. Where no income is distributed until the property has "paid out," the computation of depreciation and depletion can be omitted. Thus the form resolves itself into one of total return and remaining deficit. In new fields where the future production is uncertain and the investment large, a return of capital should be anticipated first. The Ranger Oil field and the McKeesport Gas fields are excellent examples of cases, by no means rare, where a company if it haa been aware of its investment and reserve, could have sold a producing well and probably have realized a large profit rather than a later loss.

Maps

Maps.—A comprehensive map is an essential necessity and gives information in concise and simple form. The date of completion of each well, depth, and a good set of symbols for different producing sands and capacity, may sometimes be entered on a map to very good advantage. Wells of neighboring companies should be entered on the map in a similar manner, where data are available. More benefit than loss will result from the exchange of information about wells.

In fields where there is water encroachment, an up-to-date record of water advancement should be indicated on the maps by a water line or well symbols. Not only water encroachment, but the limits of the reservoir in pools without water, can be outlined. The map data can be supplemented by peg or other models[1] of the producing sand, although this is rarely justified except for litigation. Both the geological and engineering departments will find use for this information.

OIL

Production Records

With the smaller companies, especially where there is a general negligence in the keping of data on well production facts for appraisal are generally lacking. This may be due to failure to recognize the importance of such information, rather than poor book-keeping.

The well data found most important for appraisals are:

1—Production from the beginning of the tract.

2—On new wells, a separate record of production at least for the first month.

3—Accurate well logs, designation of sand and redrilling records.

4—Continuous record of the water content of oil produced.

Depletion Record

A chart has been drawn which shows one of many methods used in accounting for depletion.[1] It presents the payment of dividends from returned capital and can also be so broadened as to provide for a return of undistributed realized appreciation to surplus, in the case of Federal taxation.

2—To assist company officials in maintaining the proper relation of reserve acreage to production demands.

Line Loss and Field Reduction Factor

Calculation of line loss is necessary:

1—To permit calculation of field production from consumers sales, and

2—To make known the efficiency of the various lines.

The field valuation factor is used where production in the field is calculated by a flow test. The factor varies from year to year with operating conditions. Where royalties are being paid on the basis of the quantity of gas purchased in the field, this correction factor should be carefully found and frequently revised to meet the changing conditions.

Well Records

The geological department requires the drillers' records for each well. These should give the sands penetrated, with the textures of each, the gas, oil or water encountered, the depth of each, the time taken to drill the well, the casing and tubing record, the location of the packer and other facts. This will permit the correlation of the sands later. The depth of the well and the tubing and casing record are necessary for the accurate calculation of the volume of the hole and for the estimation of flow by minute tests of pressure above line. It is important to obtain the name of the producing sand, in order to classify wells for making and using the decline curve for the pool when estimating reserves.

OPERATED LEASES LEDGER

Lease No. 2956 Farm Name—John Doe
Township—Springhill County—Greene State—Pa. Section.......... Range........

Date	Explanation	Capital Sum	1913	1914	1915	1916	1917	1918	1919	1920	1921	1922
	Fair market value 3-1-13	$69,000.00	$7,000	$6,000	$4,000	$3,800	$3,500	$3,200	$3,000	$2,700		
	Balanee brought forward		69,000	62,000	56,000	52,000	48,000	44,700	41,500	38,500	25,800	
	Capital sum added during yr.		None	None	None	None	None	None	None	None		
	Total eapital sum		69,000	62,000	56,000	52,000	48,000	44,700	41,500	38,500		
	Deduct depletion		7,000	6,000	4,000	3,800	3,500	3,200	3,000	2,700		
	Balanee forwarded		62,000	56,000	52,000	48,200	44,700	41,500	38,500	25,800		

(a) Upon cost, if acquired after February 28, 1913; or
(b) Upon the fair market value as of March 1, 1913, if aequired prior thereto; or
(e) Upon the fair market value within thirty days of discovery, in the ease of oil wells "discovered" by taxpayer after Feb. 28, 1913, where the fair market value is disproportionate to eost.

Gas

With gas companies the records are still more incomplete than with oil companies. The difficulty arises mainly thru the indifference regarding production records. If an oil company fails to keep production records, run tickets can usually be obtained from the pipe lines and the amount ascertained. Gas is not run from tanks like oil and the only record is generally the final sales. These have little value for appraisal except where no new wells have been drilled.

Production Records.—For gas wells, where no meters are installed, some kind of periodic test provides the basis for an type of test should be adopted and consistently carried out. Changing from one method of testing to another practically nullifies the previous readings for the purpose of predicting future reserves.

Time in Line.—A record of the days of each year that a well has been turned into the line will serve at least two purposes in appraisal.

1—The probable change in the demand on wells in order to predict the days in line each year in the future for the purpose of reserve estimates.

Acreage Records

Every company has three classes of acreage (a) developed (b) partly developed and (c) undeveloped. The developed acreage establishes the visible reserves, the partly developed and undeveloped acreage the prospective reserves. The annual calculation of the amount of undrilled acreage to each customer and the number of producing acres to each customer will assist both the land and geological departments in estimating the future requirements.

Number of Customers

Several companies have been noted that had no definite record of their domestic and industrial consumers. Such data at the present critical time in the

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[1]Huntley, L. G., Geological features illustrated by models—Read before March, 1922, meeting of Amer. Assoc. of Pet. Geol.

[1]Johnson, Huntley & Somers, Business of Oil Production, John Wiley & Sons, 1922.

natural gas situation should be obtained. Possible legislation that would conserve the supply for domestic consumers only, will put on each company the burden of adjusting prices on the basis of possible future demand and operating expense: The future demand cannot be obtained unless the past demand per customer is available. The number of meters installed is a fair approximation, if the number of people supplied by each does not vary too greatly.

CHAPTER XXIII

APPRAISAL FOR THE PURPOSE OF FIXING RATES

Gas

Purpose

A corporation seeks or should seek an increase in rates when the earnings resulting from existing rates are inadequate and do not permit a reasonable return on the investment. A natural gas utility because its business is to sell a commodity which cannot be reproduced must explore for and exploit sufficient quantities of the product to maintain its existence. Increasing labor costs, cost of operation and investment requirements force the owner to guard the safety of his investments by a larger return.

Necessity for Rate Fixing Commissions

A rate fixing commission is a body representing the public and created to protect the rights of the people against a monopoly. Certain corporations have franchises granting them exclusive rights in a community. Such rights, even tho some franchises are limited, having been granted by the public, must be safeguarded against abuse. In many cases competition does exist, and prices would thus be automatically controlled if it were not that a public utility corporation can demand no change in rate until it is sanctioned by the commission.

A public utility corporation requires, as a rule, a large initial expenditure and expects only a slow return on the investment. Such a corporation is therefore often granted unusual privileges in the franchise such as the right of eminent domain. These privileges if uncontrolled might result in wrong to the public.

That competitive public utility corporations result in an ultimate detriment to public interests has more than once been demonstrated. To expect full and free competition, especially in natural gas utilities, adds to the expense which must first be borne by the corporation but is eventually thrust upon the public. Monopoly is an economic advantage to the company and if safeguarded by an efficient commission also to the public.

Commissions may be federal, state or municipal. Massachusetts was the pioneer in establishing commission control of public utility corporations. Other states followed in succession, the greatest progress being made after 1900, until at present nearly every state has its controlling body.

The right to regulate rates is generally recognized. As long as fair regulation is exercised, the owner will be assured of a reasonable return and protection against unfair competition.

Regulation must be Constitutional and on Fair Value

Several United States Supreme Court decisions state that the forcing of unjust rates on a company is in fact a confiscation of private property. A company deprived of the power to charge reasonable rates for the use of its property without proper investigation by a judicial body is deprived of the lawful use of its property in violation of the constitution of the United States.

A company is entitled to ask a fair return upon the value of that which it furnishes for the convenience of the public and it cannot be expected to furnish its property for the benefit of the public without just compensation. This view of return on fair value has developed to such a point that it is generally conceded now that the rate must be sufficient to maintain this fair value.

To obtain fair value, the present day practice is to find the value of the physical plant as such and in addition the intangible values, namely the expenditures necessary to create and develop the business up to the state of satisfactory usefulness. Valuation on physical structure alone, does not comprehend the plant as an operating and thriving organization.

Components of Rate on Fair Value

That fair present value means the reproduction of the plant in its present state of usefulness is shown by a long list of court decisions in favor thereof.

Every rate adjustment must comprehend other considerations aside from a return of investment. A rate should provide four things:

First—A reasonable interest on the investment determined.

Second—Current operating expenses, including repairs and replacements mostly in the nature of capital expenditures.

Third—In addition to interest an annuity or amount toward redemption of capital which will eventually return the investment. This annuity should properly consider its improvement by compound interest.

Fourth—A return for the intangible values in valuation of the business which may be stated also as value of service rendered.

The Basis of Value

It is difficult to outline any recognized or acceptable method for determining the fair value. There are, however, certain broad principles involved which are generally taken as essential to the determination of value. The detailed procedure depends largely upon the opinions of the investigator, there being much opposition to certain methods. Each valuation must be a result of the study both of the conditions in the locality and of the corporation.

The items entering into the fixing of the tariff for the service rendered have been previously listed. The fair value necessary to derive this rate depends in general upon certain fundamental findings which are:—

First—The original cost of the assets.

Second—The depreciation to date.

Third—The cost of reproducing the property at current prices.

Fourth—The gross income.

Fifth—The operating expenses.

Sixth—The value of the service rendered as such.

The part that some of the above should play is in dispute.

The sixth point when granted is especially significant in natural gas utilities inasmuch as the commodity is generally sold for less than fifty percent of the price of the manufactured substitute.

In arriving at a value for the fixing of rates, the appraiser will necessarily be guided by the court ruling in regard to permissable methods. Such limitations of course may lead to divergence from the recognized principles of sound appraisal. The legal profession must be guided by law and precedent, if there is any. An engineer disregards court decisions entirely and makes a valuation which in his opinion is just unless of course it is for a purpose where these legal decisions are controlling. In this case the valuation being made avowedly for such a purpose is properly made in accordance with these decisions.

The authors recall one such incident where an appraiser based the valuation upon future earnings. The opposition held that the value could not be accepted, as the future earnings were dependent upon the rates postulated and such rates were not to be prematurely contemplated in the fixing of the value.

Factor Bearing on Valuation

The fair value is essentially the cost to reproduce a similar plant new, less the depreciation and depletion of existing properties, structures and materials. There are many factors directly or indirectly bearing on this valuation. In some respects these factors are actual checks on the ultimate results.

The elements having a direct or indirect bearing on the valuation are:—

1—Combined market value of securities.
2—Earning value of franchise in purchase cases.
3—Working capital.
4—Relation of service rendered to value.
5—Amount of repairs and replacements.
6—Taxes and valuations for taxation.
7—Intangible value.
8—Annual depreciation and depletion.
9—Net earnings.
10—Volume of business.
11—General office or executive expenditures.
12—Original cost.

13—Value of assets for other than purpose intended.

14—Amount of outstanding stocks and bonds.

15—Cost of like service rendered elsewhere.

16—The past history.

17—The capitalization of the enterprise.

18—The cost of reproduction anew.

19—The depreciated or present value.

Those elements having no bearing on valuation are:—

1—Good Will in case of monoply.

2—Paving paid for by others than the corporation.

3—Appreciation in value due to improvements made by others.

Methods of Making Valuations

The valuation methods for physical properties can be deducted from the information in the chapter on "Valuation of Physical Property" with the qualifications given in this chapter.

Land values may be rightfully included in the appraisal if such lands are actually and necessarily devoted to public use. The recognized basis for establishing land values is on the sale price of transactions of similar property in the vicinity. If a higher price would be demanded of a public service corporation over that if property was sold to a private individual this higher price should be used. Of course improvements existing on the property must be valued on the basis of its value to the utility. Appreciation is a permissable consideration in the fixing of the value. Value for assessment has but little bearing on the actual value, as such values are often inequitable because incompetently or hastily determined.

The value of gas rights and of land held in fee for its gas content depends upon the fair market value established by sales. Analytical appraisal with modifications to meet the legal requirements can serve as a guide to the fair market value in the absence of sales.

The valuation of intangible assets such as good will, going concern value, and going value are discussed in the chapter on Valuation of Intangibles.

Effect of Price and Consumption

Before the officers of a public utility corporation request an increase of rates, they should recall that consumption decreases as rate increases. To determine the effect, a graph should be prepared showing the maximum income at various rates. To make such a chart, it is first necessary to prepare a scatter diagram of domestic per capita consumption, against the rate for as many cities, that are reasonable comparable, as is possible.

Costs, Prices, Asset and Other Comparisions

One of the most satisfactory means of illustrating the reasons why a change in price is essential is by means of tabular or graphical comparisons. Some of these have been discussed in the chapter on Prediction of Future Prices and other chapters.

Appraisal of Oil and Gas Properties

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CHAPTER XXIV

Appraisal of Casinghead Gasoline Production

IN CONNECTION with both the oil and gas industries the manufacture of gasoline from natural gas has become an important source of revenue. Natural gas companies extract the product when they find that a gas is not too lean. These companies have the advantage of often being able to establish their gasoline extraction plants in one or more large units on main transmission lines. Gasoline plants for oil companies can ordinarily serve but one pool except where these overlap.

Principles of Appraisal.—For finding the worth of a casinghead gas contract or of a gasoline plant, or the gasoline value of a lease the appraiser uses the same fundamental principles as in oil and gas appraisal. Frequently the manufacture of the gasoline is so closely allied with the production of either oil or gas that a combined valuation is possible. In general it is essential that estimates be made of future yield, future prices, future operating cost, future development and risk. The plant where no new gas is available, has only salvage value when the life of the present supply terminates. Thus the present worth of income from gross sales gives the value desired. The plant is merely a function in the creating of the value, especially where a plant is under the operation and appraisal is made for the purpose of purchase or sale. But where a plant is contemplated but not yet possessed, two separate valuations evolve; one of the supply and its net value; the other of the installation of a plant. If the cost of the plant exceeds the probable net receipts, the project is non-commercial. If it does not exceed the net receipts, then the difference between net present value of deferred receipts and discounted cost of the plant is the amount one would be warranted in paying for the right to the supply of casinghead gas.

Casinghead Gasoline Contracts Tangible Assets.—For federal taxation it has been held that under certain conditions contracts for casinghead gasoline are assets that may be valued for depreciation and depletion.

The following is an extract to that effect from the Regulations: "Regulation 45, Article 223—Charges to Capital and to Expense in the Case of Oil and Gas Wells:— * * * casinghead gas contracts have been construed to be tangible assets and their cost may be added to capital account returnable through depletion * * * ."

Estimation of Future Yield of Gasoline.—Future gasoline reserves are determined by estimating the probable gas supply and potentiality yield of gasoline.

The probable gas supply can be calculated by methods similar to those described in Chapter VI as applied to oil or natural gas. If records are available the past history should be the basis of future estimates, if not, an average or composite decline curve should be used with due caution, as to the location of tract on the structure, variation from the average in gasoline content of the gas and other factors affecting yield. A composite or average curve cannot be as readily applied as in the case of oil or natural gas, as the element of efficiency of the extraction plant is a controlling factor in the amount of gasoline produced. Also, the gas from different wells varies greatly in both volume and quality.

For the past history needed to determine the production, the records from the plant are generally used. Special meters are built for the purpose. These instruments are sensitive and calibrated to handle certain amounts of gas. It should be known whether the meters are properly used, frequently tested, and kept clean. If improperly used, the measurements may have little value for appraisal purposes. Having accurate measurements, the gasoline production as well as the casinghead gas yield can be tabulated in time units, and curves can be constructed on both to find the trend. Unless individual well gas tests of gasoline content are known, a composite decline curve cannot be drawn. The curve as found from the measurements at the plant, is an average and likely to be influenced by the turning in of new wells into the gathering lines. If such a procedure were continuous, only production and not well decline would be ascertainable.

The life of most wells as casinghead producers depends upon their life as oil producers. Therefore, an oil decline curve used in conjunction with a curve of increased gasoline yield per M. cu. ft. with the age of the well, may be taken for estimating the future production if a real gasoline yield per well curve cannot be made. It is, of course, much less reliable. It should not be overlooked that occasions arise where the economic limit of oil production is prolonged by reason of the casinghead gas output, and cases are not infrequent where the operations are conducted at a loss as far as the oil production alone is concerned, but where the added value of the gas provides an operating profit. Actual instances exist in Glennpool where some wells provide more barrels of gasoline than barrels of oil.

The cause of change in richness of gas is the change in pressure during the life of the well.[1] With high pressure only such gases as methane and ethane absorbed in the oil are liberated, but as the pressure is reduced by the escape of gas, wet gases, held in solution in the oil, are released. The composition of the gas changes as the pressure is reduced. Thus the proportion of propane and butane and heavier hydrocarbon vapor increases so that the gas becomes increasingly wet and valuable for gasoline extraction. The proportion of gas absorbed by the oil is decreased at high temperature, but is greatly increased under high pressure in accordance with Henry's law of gases.[2] Gas pumping reduces pressure and causes the gases in solution to be freed to a greater degree. In laboratory experiments oil has been made to froth by decreasing the pressure on the vessel.

When contemplating the installation of a new plant or the purchase of gas in a locality where no gas has as yet been utilized for gasoline extraction one of the various methods in practice for testing the capacity of such wells will have to be taken. Wells are easily tested for flow and specific gravity. By a small absorption or compression testing apparatus the quality of the gas is determined.

A small portable compressor may be used to make tests of the casinghead gas for a compression plant. The Newton Absorption Tester, Dykeman Absorber, or any of the charcoal absorption testing apparatus, are more often used to find the gasoline content.[3] Some of these are applicable to lean natural gas, also. There are devised several types of coil absorbers to use with dry natural gas. After the quantity and quality of the gas has been determined, an estimate of future reserves can be made with these data as the basis. A decline curve of the amount of gas, with correction factors applied for change in

[1]This is a controversial theory and has been variously settled by different states. However, as stated herein, it is an expression of the author's views.

[2]J. O. Lewis, Methods for Increasing the Recovery from Oil Sands, Bull. 148, Petr. Tech. 37, Bureau of Mines.

[3]Parts 5, 6, and 7, of Westcott's Handbook of Casinghead Gas.

[4]Oil and Gas Manual, p. 53.

quality is much to be preferred to one of the oil produced, when data permits.

Following is a table suitable for tabulating data necessary in the appraisal:[4]

Casinghead Gas

(a) Quantity of casinghead gas produced by months from date of first production to date of acquisition.

(b) Quantity of casinghead gas produced by months for period subsequent to date of acquisition.

(c) Average number of wells contributing to this production each year.

(d) In case the gas is sold, give the amount received each month for gas mentioned in (a) and (b).

(e) Quantity of gasoline in gallons recovered each year from casinghead gas, mentioned in (a) and (b).

(f) Amount received each month for gasoline mentioned in (e).

(g) Average price per gallon received for gasoline mentioned in (e).

(h) Production of oil by months for the wells from which this casinghead gas is taken. Give this information by individual wells if possible; if not, then by tracts with number of wells producing each month. When monthly records are not available give data by years.

Future Price.—As in the case of oil price predictions, those for gasoline involve a long time study and much data; nearly all the information collected for oil price predictions can be used in estimating future gasoline prices.

The factors having most bearing on the future price of gasoline are as follows:

1. Condition of the petroleum market —the prices and production each year by fields.
2. Annual production of casinghead gas and refinery gasoline.
3. Average price each year received for gasoline.
4. Inter-state movement of gasoline stocks.
5. The number of pleasure cars registered each year with data as to the approaching stage of saturation of the market with this type of car.
6. Number of tractors in use each year.
7. Amount and price of other refinery products (This is not always essential, since in 1921 the gasoline price was kept up in spite of the poor market for other refinery products, the operating costs being paid mainly by gasoline sales.)
8. Possible substitutes for gasoline.
9. Possible changes in type and power of gasoline engines.
10. Possible adoption of other than gasoline burning motors.
11. Increased efficiency in refining processes that may produce greater amounts of gasoline and other desirable products per barrel of crude oil.
12. Restriction of gasoline consumption in the interests of conservation.
13. A change in the demand for pleasure automobiles, to one mainly of replacements with relatively few new owners.

Doubtless the petroleum market controls the movement of gasoline prices more than any other one thing. An exhaustive study of all things affecting price trend of crude oil should precede the construction of a future price curve of gasoline. In 1920 the production in the United States was equivalent to about forty barrels of oil per motor vehicle. The production can not continue increasing rapidly enough to keep up this ratio. The limit of production has almost been reached. With a drop in petroleum and gasoline production, a decided increase in price will set in. Fuel substitutes as volatile as gasoline, other than that from shale oil, can at the utmost reach only one-fourth of the 1919 gasoline demand.[5]

Pogue brings out that the future demand of gasoline for motor vehicles is not likely to be greater than the supply.[6] He contends that it will be a growth by a diminishing rate. As an example is given the fact that the increase in population in any given country, if plotted on quadrillé paper, traces a curve of double flexure, in its earlier concave upward and later downward. Thus the later growth indicates stabilization through development. A possible shift to a greater use of steam motors and electric cars with an increase of price of gasoline should be seriously considered.

The formula for predictions on the principle outlined was devised by Gomperz and only lately applied for economic work by R. B. Prescott.[7] The diagrams accompanying the article by Pogue are given therein to show the possibilities of using the principles advanced in making predictions.

Future Operating Costs.—These are readily predicted from the present cost of running the present plant or one of similar type and efficiency. For less refined valuation one may assume that the costs will remain uniform throughout the life of the plant.

Royalty rates when on a sliding scale will cause a fluctuation in operating costs. Most rates of this type involve price and will have to be predicted in conjunction therewith. Flat rate contracts will affect costs proportionately to the amount of gas produced and will necessarily be predicted with this in view. The four principal methods of paying for the gas are[8]:

(1) Flat rate. A uniform price per M. cu. ft. of gas used.

(2) Sliding scale of the price of gasoline. The scale may be a fixed percentage of the sale price or it may increase in percentage with increase in the sale price.

(3) Percentage of gross receipts. This type of contract provides for a fixed percentage of the gross income realized from the gas recovered or the operation of the plant.

(4) Quality of the gas. In this case tests are made of the casinghead and royalty paid on the basis of the productivity and a percentage of the price given at two or more designated levels.

The sale price may be that of the local market, loading rack, f. o. b., or Chicago tank wagon. There may be a further variation in the application of the percentage as cents per thousand cu. ft., or cents per gallon of gasoline. In the former case an example is 3c per M. cu. ft. for the gas when the price of gasoline is 15c a gallon with a ½c increase in price per M. cu. ft. for each 2c increase in gasoline price, or instead of cents on the gallon it may be on the gallons actually produced per M. cu. ft. In the latter case it may be 2c on 10c gasoline and then ratably increased with each increase in sale price.

Factors Indirectly Affecting Valuations.—There are numerous indirect elements which must be considered in making an appraisal on a gasoline plant or contract. A few of these will be discussed separately.

1. **Accessibility.**—This includes accessibility to railroad, to gas supply, to water supply, and to repair supplies. The location near a railroad is advantageous for loading the final product and receiving the naphtha if blending is done at the plant. It is a question as to whether proximity to a railroad or to the source of casinghead gas should be given the preference in establishing a location. An estimate of losses through leakage, of the differing costs, and especially consideration of the distance and the condition of roads in either event will help determine the final location of the gasoline plant.

2. **Efficiency of operation.**—This covers both plant and lease efficiency. Changes in the management of the plant may result in a greater or a lesser production. A number of processes such as cooling and blending may be done in various ways with varying results. Lease efficiency, especially where the oil operator is independent from the plant operator, is more difficult to obtain, the degree of vacuum, if any, the choice of time for pumping the well, the admission of air into the lines by poor connections where there is a vacuum and salt water encroachment. are all matters which if not taken care of in a co-operative spirit may cause the gasoline producer much loss of profit.

3. **Climate.**—Hot climates cause a lower efficiency and coolers may materially decrease yield or increase costs.

4. **Well differential.** — Some wells give off a leaner gas than others with a consequent effect on plant production on the days that such wells are operated.

5. **Co-operation.**—Besides the co-operation of lease operators it is advantageous to have the co-operation of the firm supplying the blending materials.

[5] A. W. Ambrose, Cal. Oil World, May 26, 1921, Vol. XIII No. 662, p. 82.

[6] Future Demands on Oil Industry of U. S., Oildom, May, 1922.

[7] The equation and discussion thereof is given in Automotive Industries, Nov., 1921, p. 954.

[8] Valuation Factors of Casinghead Gas Industry, by Oliver U. Bradley, Vol. LXV, p. 400, Bull. A. I. M. E., 1921.

Delay in shipments may result in considerable loss thru evaporation of the gasoline. Ownership in one corporation of refining and gasoline plant, therefore, actually adds value.

6. **Other factors.**—Other factors to take into consideration are road conditions, supply of labor, and geological structures.

Valuation of Physical Property.—Where the supply of gas is limited to the life of the given wells and no new supply is in sight, the valuation of the gasoline plant will depend upon the net income resulting from the gas available only. In this event, the plant is an integral part of the present worth of these receipts, not an additional value except as to salvage.

Obsolescence in the type of machinery used is a frequent cause for installing new equipment. New developments are continually being made in type and efficiency of equipment. Thus it may be profitable to replace an old plant by one of newer design and this if foreseen will make an important difference in the valuation. The methods for valuing of gasoline plants are similar to those outlined in the chapter on "The Valuation of Physical Property." Generally, estimates on cost of building the plant can be had from a construction company. The following outline of factors in the appraisal of casinghead gas summarizes the subject:—

(a) **Gas Data—**
1. Specific Gravity.
2. Quantity.
3. Quality.
4. Impurities.
5. Future annual supply.

(b) **Sand and Well Data—**
1. Number of wells available.
2. Spacing of wells.
3. Depth.
4. Thickness of sand.
5. Water conditions.
6. Geological structure.
7. Age of wells.
8. Gravity of oil.
9. Pumping periods.
10. Efficiency of operation.
11. Risk of productivity of new wells.

(c) **Cost Data—**
1. Cost of plant.
2. Cost of gathering and vacuum lines.
3. Other miscellaneous equipment.
4. Cost of operating by years.

(d) **Other Factors—**
1. Lease titles.
2. Railroad facilities.
3. Roads.
4. Location of supply firms.
5. Labor.
6. Water supply.
7. Co-operation of lease operators.
8. Climate.
9. Well differential.
10. Sale value of residue gas.

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